SECTION 5.2 AIR QUALITY
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5.2 AIR QUALITY

This analysis of the potential air quality impacts of the Tesla Power Project (TPP) was conducted according to California Energy Commission (CEC) power plant siting requirements. The analysis also addresses the Bay Area Air Quality Management District (BAAQMD) requirements for Authority to Construct (ATC) and Permit to Operate (PTO). The details of the analysis are contained in the following sections:

- Section 5.2.1 describes all applicable laws, ordinances, regulations, and standards (LORS).
- Section 5.2.2 describes the local environment surrounding the TPP site. Meteorological data, including wind speed and direction (i.e., windroses), temperature, and precipitation are discussed, and ambient concentrations for the appropriate criteria pollutants are summarized.
- Section 5.2.3 provides an analysis of best available control technology (BACT) for gas-fired turbines, and explains how the use of dry low nitrogen oxide (NO_x) combustors and selective catalytic reduction (SCR) with ammonia injection meet NO_x BACT requirements. BACT controls for the diesel generator, diesel fire water pump engine, and cooling tower are also proposed. Also, mitigation of fugitive dust during construction is discussed.
- Section 5.2.4 evaluates the TPP's air quality impacts from NO_x, carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOCs) also called precursor organic compounds (POCs), and particulate matter less than 10 micrometers (μm) in diameter (PM_{10}) emissions. Emission estimates are presented for these pollutants for project construction and operation over a range of operating modes, including startup and shutdown. The modeling analysis conducted for nitrogen dioxide (NO_2), CO, SO_2, and PM_{10} is presented. The results show no negative impacts to the California and federal Ambient Air Quality Standards (AAQS) from the TPP. Also, air quality related values (AQRVs) are evaluated. No negative impacts to visibility, terrestrial or aquatic resources are expected from the TPP.
- Section 5.2.5 describes the TPP emission requirements and planned use of emission reduction credits (ERCs).
- Section 5.2.6 describes TPP compliance with all applicable LORS. Also, Table 5.2-36 summarizes TPP compliance with each applicable LORS.
- Section 5.2.7 lists the agency contacts for the air quality assessment.
- Section 5.2.8 lists the references for the air quality assessment.

Some relevant information is also presented in other sections of this Application for Certification (AFC), including the project description (see Section 3.0), an evaluation of toxic air pollutants (see Section 5.15) and information related to the fuel characteristics (see Table 3.4-8), and heat rate and expected capacity factor of the proposed facility (see Section 2.0).

5.2.1 Laws, Ordinances, Regulations, and Standards

The applicable LORS related to the potential air quality impacts from the proposed project are described below. These LORS are administered (either independently or cooperatively) by U.S. EPA Region IX, the CEC, the California Air Resources Board (CARB), and the BAAQMD.

5.2.1.1 Ambient Air Quality Standards

U.S. EPA, in response to the federal Clean Air Act (CAA) of 1970, established federal AAQS in 40 Code of Federal Regulations (CFR) 50. The federal AAQS include both primary and secondary standards for six "criteria" pollutants. These criteria pollutants are ozone (O_3), CO, NO_2, SO_2, PM_{10}, and lead (Pb). Primary standards were established to protect human health, and secondary standards were designed to protect property and natural ecosystems from the effects of air pollution.

The 1990 Clean Air Act Amendments (CAAA) established attainment deadlines for all designated areas that were not in attainment with the federal AAQS. In addition to the federal AAQS described above, a new federal standard for particulate matter less than 2.5 μm in diameter ($PM_{2.5}$) and a revised O_3 standard were promulgated in July 1997. The $PM_{2.5}$ standards have not been implemented. Under an interim policy, the PM_{10} and 1-hour O_3 standards will continue to be implemented for the next several years while the new standards are being phased in.

In 1988, as part of the California Clean Air Act, the State of California adopted the California AAQS that are in some cases more stringent than the federal AAQS. The state and federal AAQS are summarized in Table 5.2-1.

The U.S. EPA, the CARB, and the local air pollution control districts determine the air quality attainment status of designated areas by comparing local ambient air quality measurements from the state or local ambient air monitoring stations with the federal and California AAQS. Those areas that meet ambient air quality standards are classified as "attainment" areas; areas that do not meet the standards are classified as "nonattainment" areas. Areas that have insufficient air quality data may be identified as unclassifiable areas. These attainment designations are determined on a pollutant-by-pollutant basis. The Bay Area has been designated as a federal nonattainment area for O_3 and as a state nonattainment area for O_3 and PM_{10}. The attainment status for all other criteria pollutants is considered attainment. Table 5.2-2 presents the attainment status (both federal and state) for the Bay Area.

As mentioned above, both U.S. EPA and the CARB are involved with air quality management in the Bay Area along with BAAQMD. The area of responsibility for each of these agencies is described below.

Table 5.2-1. Relevant Federal and California Ambient Air Quality Standards

Pollutant	Averaging Time	California AAQS[a,b]	Federal AAQS[b,c]	
			Primary	Secondary
Ozone (O_3)	1-hour[d]	0.09 ppm (180 μg/m^3)	0.12 ppm (235 μg/m^3)	Same as primary standard
Carbon Monoxide (CO)	8-hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)	
	1-hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)	
Nitrogen Dioxide (NO_2)[e]	Annual (Arithmetic Mean)		0.053 ppm (100 μg/m^3)	Same as primary standard
	1-hour	0.25 ppm (470 μg/m^3)		
Sulfur Dioxide (SO_2)	Annual (Arithmetic Mean)		0.03 ppm (80 μg/m^3)	
	24-hour	0.04 ppm[f] (105 μg/m^3)	0.14 ppm (365 μg/m^3)	
	3-hour			0.5 ppm (1,300 μg/m^3)
	1-hour	0.25 ppm (655 μg/m^3)		
Respirable Particulate Matter (PM_{10})	Annual (Geometric Mean)	30 μg/m^3		Same as primary standard
	24-hour	50 μg/m^3	150 μg/m^3	
	Annual (Arithmetic Mean)		50 μg/m^3	
Fine Particulate Matter ($PM_{2.5}$)	24-hour	No separate state standard	65 μg/m^3	Same as primary standard
	Annual (Arithmetic Mean)		15 μg/m^3	
Visibility Reducing Particles	1 observation	See footnote "g"	No federal standard	No federal standard

Notes:

AAQS = Ambient Air Quality Standard

mg/m^3 = milligrams per cubic meter

μg/m^3 = micrograms per cubic meter

ppm = parts per million

a Title 17, California Code of Regulations, California AAQS for ozone (as volatile organic compounds), carbon monoxide, sulfur dioxide (1-hour), nitrogen dioxide, and particulate matter (PM_{10}), are values that are not to be exceeded. The visibility standard is not to be equaled or exceeded.

b Concentrations are expressed first in units in which they were promulgated. Equivalent units are given in parentheses and based on a reference temperature of 25°C and a reference pressure of 760 mm of mercury. All measurements of air quality area to be corrected to a reference temperature of 25°C and a reference pressure of 760 mm of mercury (1,013.2 millibar); ppm in this table refers to ppm by volume, or micromoles of pollutant per mole of gas.

c 40 CFR 50. National AAQS, other than those for ozone and based on annual averages, are not to be exceeded more than once a year. The ozone standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than one.

d A new federal 8-hour ozone standard was promulgated by U.S. EPA on July 18, 1997 but was invalidated by the United States Supreme Court in February 2001. The federal 1-hour ozone standard continues to apply in areas that violated the standard.

e Nitrogen dioxide (NO_2) is the compound regulated as a criteria pollutant; however, emissions are usually based on the sum of all oxides of nitrogen (NO_x).

f At locations where the state standards for ozone and/or PM_{10} are violated. National standards apply elsewhere.

g In sufficient amount to reduce the prevailing visibility to less than 10 miles when the relative humidity is less than 70%. "Prevailing visibility" is defined as the greatest visibility which is attained or surpassed around at least half of the horizon circle, but not necessarily in continuous sectors.

U.S. EPA has ultimate responsibility for ensuring, pursuant to the CAAA, that all areas of the United States meet, or are making progress toward meeting, the federal AAQS. The state of California falls under the jurisdiction of U.S. EPA Region IX, which is headquartered in San Francisco. U.S. EPA requires that all states submit State Implementation Plans (SIPs) for nonattainment areas that describe how the federal AAQS will be achieved and maintained. U.S. EPA has delegated this attainment responsibility to the CARB.

CARB, in turn, has delegated attainment responsibility to regional or local air quality management districts (or air districts), such as BAAQMD. CARB is responsible for attainment of the California AAQS, implementation of nearly all phases of California's motor vehicle emissions program, and oversight of the operations and programs of the regional air districts.

Each air district is responsible for establishing and implementing rules and control measures to achieve air quality attainment within its district boundaries. The air district also prepares an air quality management plan (AQMP) that includes an inventory of all emission sources within the district (both man-made and natural), a projection of future emissions growth, an evaluation of current air quality trends, and any rules or control measures needed to attain the AAQS. This AQMP is submitted to CARB, which then compiles AQMPs from all air districts within the state into the SIP. The responsibility of the air districts is to maintain an effective permitting system for existing, new, and modified stationary sources, to monitor local air quality trends, and to adopt and enforce such rules and regulations as may be necessary to achieve the AAQS.

Table 5.2-2. Federal and State Attainment Status for the Bay Area

Pollutant	Federal Attainment Status	State Attainment Status
Ozone	Nonattainment	Nonattainment
CO	Attainment	Attainment
NO_2	Attainment	Attainment
SO_2	Attainment	Attainment
PM_{10}	Attainment	Nonattainment
Lead	Attainment	Attainment

5.2.1.2 Prevention of Significant Deterioration Requirements

In addition to the ambient air quality standards described above, the federal PSD program has been established to protect deterioration of air quality in those areas that already meet national ambient air quality standards. Specifically, the PSD program specifies allowable concentration increases for attainment pollutants due to new emission sources. These increases allow economic growth while preserving the existing air quality, protecting public health and welfare, and protecting Class I areas (national parks and wilderness areas). The PSD regulations require major stationary sources to undergo a preconstruction review that includes an analysis and implementation of BACT, a PSD increment consumption analysis, an ambient air quality impact analysis, and analysis of AQRVs.

U.S. EPA Region IX has delegated PSD permitting authority to the BAAQMD. BAAQMD Regulations 2-2-304 and 2-2-305 specify the incremental emission triggers for SO_2, NO_x, PM_{10}, and CO as shown in Table 5.2-3. For project emissions of SO_2, NO_x, or PM_{10} above these PSD triggers, the applicant must demonstrate through modeling, in accordance with BAAQMD Regulation 2-2-412, that such emissions would not interfere with the attainment or maintenance of the applicable NAAQS and would not cause an exceedance of the applicable PSD increments shown in Table 5.2-4. For project emissions of CO that exceed the trigger levels, the applicant must demonstrate through modeling that the increase in emissions would not interfere with the attainment or maintenance of the CO NAAQS. Allowable PSD increments for SO_2, NO_2, and PM_{10} are summarized in BAAQMD Regulation 2.2.232 and are presented in Table 5.2-3. Point Reyes National Seashore is the only Class I Area within the BAAQMD boundaries. It is approximately 102 km from the Tesla site. All other areas within the district are Class II areas; there are no Class III areas within the BAAQMD.

Table 5.2-3. Prevention of Significant Deterioration Threshold Triggers

Pollutant	Significant Thresholds (tpy)	Project Emissions Increase (tpy)
SO_2	40	29.5
NO_2	40	245.8
POC*	40	58.9
PM_{10}	15	195.6
CO	100	468.5
Lead (Pb)	0.6	<0.6 (negligible)

*The PSD threshold for POC is not applicable to the TPP because POC is regulated as a precursor to ozone and the BAAQMD is nonattainment for ozone.

Table 5.2-4. Prevention of Significant Deterioration Allowable Increments (μg/m³)

Standard	Class I Area	Class II Area	Class III Area
PM_{10} Annual Arithmetic Mean	4	17	34
PM_{10} 24-Hour Maximum	8	30	60
SO_2 Annual Arithmetic Mean	2	20	40
SO_2 24-Hour Maximum	5	91	182
SO_2 3-Hour Maximum	25	512	700
NO_2 Annual Arithmetic Mean	2.5	25	50

5.2.1.3 Acid Rain Program Requirements

Title IV of the CAAA applies to sources of air pollutants that contribute to acid rain formation, including sources of SO_2 and NO_x emissions. The BAAQMD has received delegation from U.S. EPA for Title IV implementation under its Title V Operating Permit program. Allowances of SO_2 emissions are set aside in 40 CFR 73. Sources are required to obtain SO_2 allowances, to monitor their emissions, and obtain SO_2 allowances when a new source is permitted. Sources such as the proposed project that use pipeline-quality natural gas are exempt from many of the acid rain program requirements. However, these sources must still estimate SO_2 and CO_2 emissions, and monitor NO_x emissions with certified continuous emissions monitoring systems (CEMS). All subject facilities must submit an acid rain permit application to U.S. EPA 24 months before commencement of operation.

5.2.1.4 New Source Performance Standards

New Source Performance Standards (NSPS) have been established by U.S. EPA to limit air pollutant emissions from certain types of new and modified stationary sources. The NSPS regulations are contained in 40 CFR 60 and cover nearly 70 source categories. Stationary gas turbines are regulated under Subpart GG. The enforcement of NSPS has been delegated to the BAAQMD, and the NSPS regulations are incorporated by reference into the district's Regulation 10. In general, local emission limitation rules or BACT requirements are more restrictive than the NSPS requirements. For example, the controlled NO_x emissions from the TPP Project's stationary gas turbines will be less than 2.0 parts per million by volume dry (ppmvd) at 15% O_2, significantly less than the NSPS limit.

The NSPS fuel requirements for SO_2 will be satisfied by the use of natural gas, and emissions and fuel monitoring that will be performed to meet the requirements of BACT will comply with NSPS, acid rain, and other regulatory requirements.

5.2.1.5 Federally Mandated Operating Permits

Title V of the CAA requires U.S. EPA to develop a federal operating permit program that is implemented under 40 CFR 70. This program is administered by BAAQMD under Regulation 2, Rule 6. Each major source must obtain a Part 70 permit. Permits must contain emission estimates based on potential-to-emit, identification of all emissions sources and controls, a compliance plan, and a statement indicating each source's compliance status. The permits must also incorporate all applicable federal requirements.

5.2.1.6 Power Plant Siting Requirements

Under the California Environmental Quality Act (CEQA), the CEC has been charged with assessing the environmental impacts of each new power plant and considering the implementation of feasible mitigation measures to prevent potential impacts. CEQA Guidelines (Title 14, California Administrative Code, Section 15002(a)(3)) state that the basic purpose of CEQA is to "prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible."

The CEC's siting regulations require that a new power plant can only be approved if the proposed project complies with all federal, state, and local air quality rules, regulations, standards, guidelines, and ordinances that govern the construction and operation of the proposed project. A project must demonstrate that project emissions will be mitigated where feasible to ensure that the impacts from the project are insignificant and will not jeopardize attainment and maintenance of the AAQS. Cumulative impacts, impacts due to pollutant interaction, and impacts from noncriteria pollutants must also be considered.

5.2.1.7 Air Toxics "Hot Spots" Program

As required by the California Health & Safety Code Section 4430, all facilities with criteria air pollutant emissions in excess of 10 tons per year are required to submit air toxic "Hot Spots" emissions information. This requirement is applicable only after the start of operation. Section 8.6, Public Health, indicates that there would be insignificant air toxics impacts from the proposed project.

5.2.1.8 Determination of Compliance, Authority to Construct and Permit to Operate

Under Regulation 2, Rule 3, BAAQMD administers the air quality regulatory program for the construction, alteration, replacement, and operation of new power plants. The proposed project is required to obtain a preconstruction Determination of Compliance from the BAAQMD. Regulation 2, Rule 3 incorporates other BAAQMD rules that pertain to sources that may emit air contaminants through the issuance of air permits (i.e., Authority to Construct and Permit to Operate). This permitting process allows the BAAQMD to adequately review new and modified air pollution sources to ensure compliance with all applicable prohibitory rules and to ensure that appropriate emission controls are used. An ATC allows for the construction of the air pollution source and remains in effect until the Permit to Operate (PTO) application is granted, denied, or canceled. For power plants under the siting jurisdiction of the CEC, the BAAQMD issues a Determination of Compliance in lieu of an ATC. The DOC is incorporated into the CEC license. Once the project commences operations and demonstrates compliance with the Determination of Compliance, BAAQMD will issue a PTO. The PTO specifies conditions that the air pollution source must meet to comply with other air quality standards and will incorporate applicable Determination of Compliance requirements.

5.2.1.9 New Source Review Requirements

New Source Review (NSR) rules establish the criteria for siting new and modified emission sources. BAAQMD has been delegated authority for NSR rule development and enforcement; the district's NSR rules are contained in Regulation 2, Rule 2. There are three basic requirements within the NSR rules. First, BACT must be applied to any new source that emits above specified threshold quantities. Second, all potential emission increases from the source above specified thresholds must be offset by real, quantifiable, surplus, permanent, and enforceable emission decreases in the form of ERCs. Third, ambient air quality impact assessments must be conducted to confirm that the proposed project does not cause or contribute to a violation of a federal or California AAQS or jeopardize public health.

5.2.1.10 Bay Area Air Quality Management District Requirements

The BAAQMD has been delegated responsibility for implementing the federal, state and local regulations on air quality in the nine-county region that includes the TPP. The proposed project is subject to BAAQMD regulations that apply to new sources of emissions, to the prohibitory regulations that specify emissions standards, and to the requirements for evaluation of air pollutant impacts for both criteria and toxic air pollutants. The following sections include the evaluation of the project's compliance with the applicable BAAQMD requirements.

5.2.1.1.1 Rules and Regulations

The following paragraphs outline the BAAQMD rules and regulations that apply to the proposed project.

Regulation 1, Section 301, "Public Nuisance" (Amended 5/01): The releases of air contaminants expected under the proposed project are not expected to "cause injury, detriment, nuisance or annoyance to any considerable number of persons or the public." In addition, none of the proposed project's sources of air contaminants are expected to endanger "the comfort, repose, health or safety of any such persons or the public, or cause injury or damage to business or property." The air quality impact analysis is designed to ensure that the proposed project will not cause any public nuisance.

Regulation 2, Rule 1, Sections 301 and 302, "Authority to Construct and Permit to Operate" (Amended 5/01): FPL Energy is submitting a copy of this application with applicable BAAQMD forms to the district to obtain an Authority to Construct and Permit to Operate for the combustion gas turbines and heat recovery steam generators. In lieu of issuing an Authority to Construct, the BAAQMD will provide the CEC a Determination of Compliance.

Regulation 2, Rule 2, "New Source Review" (Amended 5/00): The purpose of this rule is to provide for the review of new and modified sources and provide mechanisms.

Regulation 2, Rule 2, Section 302 ("Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides") stipulates that federally enforceable emission offsets are required for POC and NO_x emission increases from permitted sources that will emit more than 15 tons per year or more on a pollutant-specific basis. For facilities that emit more than 50 tons per year or more of NO_x or POC, offsets are provided at a ratio of 1.15 to 1.0. The proposed project is expected to emit more than 50 tons per year of NO_x and POC, so emission offsets would be provided as necessary. Section 303 ("Offset Requirement, PM_{10} and Sulfur Dioxide") stipulates that emission offsets would be provided at a ratio of 1:1 for facilities that will release more than 100 tons per year of PM_{10} and sulfur dioxide. The facility is expected to release more than 100 tons per year of PM_{10}, so emission offsets are required for this pollutant. No offsetting of the proposed project's SO_2 emissions will be required because the facility will release less than 100 tons per year of SO_2. Details of emission offset strategy are given in Section 5.2.4.

Pursuant to Regulation 2-2-414-1 ("PSD Air Quality Analysis"), air quality analysis was performed including meteorological and topographic data for the proposed project. This analysis includes ensuring that the emission increases caused by the facility will not cause or contribute to a violation of an air quality standard or an exceedance of any applicable PSD increment. The protocol for this modeling is presented in Appendix K-1 and the results are presented in Section 5.2.2.

Pursuant to Regulation 2-2-417 ("Visibility, Soils, and Vegetation Analysis"), an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the new or modified source and the general commercial, residential, industrial and other growth associated with the source or modification needs to be submitted with the application. The applicant need not provide an analysis of the impact on vegetation if it has no significant commercial or recreational value. Analysis of visual impacts is discussed in Sections 5.2.2.5 and 5.2.2.6.

Regulations 2-2-304 and 2-2-305 ("PSD Requirements" and "Carbon Monoxide Modeling Requirement") specify the incremental emission triggers for SO_2, NO_x, PM_{10}, and CO. For project emissions of SO_2, NO_x, or PM_{10} above these PSD triggers, the Applicant must demonstrate through modeling that no air quality standard will be exceeded. For project emissions of CO that exceed the trigger levels, the applicant must demonstrate through modeling that the increase in emissions will not interfere with the attainment or maintenance of the CO NAAQS. Section 5.2.5.2 discusses these PSD requirements further.

Regulation 2, Rule 3, "Power Plant" (Amended 10/99): This rule contains procedures for the review and standards for the approval of authorities to construct power plants. This regulation is discussed in Section 5.2.5.8.

Regulation 2, Rule 6, "Major Facility Review" (Amended 5/01): The purpose of this rule is to implement the operating permit requirements of Title V of the federal Clean Air Act as amended in 1990. This regulation is discussed in Section 5.2.5.5.

Regulation 2, Rule 7, "Acid Rain" (Adopted 9/94): The proposed project's gas turbine units will be subject to the requirements of Title IV of the Federal Clean Air Act Amendments. Allowances of SO_2 emissions are set aside in 40 CFR 73. See Section 5.2.5.3 for a discussion of acid rain program requirements.

Regulation 6, "Particulate Matter and Visible Emissions" (Amended 12/90): The proposed project will utilize the following to minimize the release of particulate matter and diminish the visibility of emissions:

- Dry low-NO_x burner technology and proper combustion practices; and
- Natural gas as the combustion fuel for the proposed gas turbines.

The emission sources of the proposed project are expected to comply with the standards set forth in Regulation 6:

- No visible emission from any of the sources will be as dark or darker than No. 1 on the Ringelmann Chart, or of such opacity as to obscure an observer's view to an equivalent or greater degree for a period more of than three minutes in any hour (Regulation 6, Section 301);
- No visible emission from any of the sources will be equal to or greater than 20 percent opacity as perceived by an opacity sensing device for a period of more than three minutes in any hour (Regulation 6, Section 302);
- No emission from any of the sources will contain particulate matter in excess of 0.15 grains per dry cubic foot of exhaust gas volume (Regulation 6, Section 310).

Calculated in accordance with Regulation 6-310, the worst-case grain loading from operation of the turbines was calculated to be less than 0.05 grain per dry standard cubic foot of exhaust gas. Therefore, the grain loading from the turbines is expected to be in compliance with this regulation. Particulate matter associated with the construction of the facility is exempt from district permit requirements but is subject to Regulation 6. It is expected that the California Energy Commission will impose conditions on construction activities that will require the use of water or chemical dust suppressants to minimize PM_{10} emissions and prevent visible particulate emissions.

Regulation 7, "Odorous Substances" (Amended 3/82): Regulation 302 prohibits the discharge of any odorous substances that remain odorous at the property line after dilution with four parts of odor-free air. Regulation 303 prohibits the discharge of ammonia in concentrations greater than 5,000 ppm. Because the ammonia emissions from the SCR units will be limited to 10 ppmvd at 15 percent O_2 each, the proposed project is expected to be in compliance with this regulation.

Regulation 8, "Organic Compounds" (Amended 10/99): This regulation limits the emission of organic compounds to the atmosphere. The proposed project is exempt from this regulation per 8-2-110 because natural gas is the only fuel used in the project. Solvents used in cleaning and maintenance are expected to comply with Regulation 8, Rule 4, by emitting less than 5 tons per year of volatile organic compounds.

Regulation 9, "Inorganic Gaseous Pollutants" (Amended 3/95): This regulation limits emissions for various compounds.

Regulation 9, Rule 1, "Sulfur Dioxide": Section 301 ("Limitations on Ground Level Concentrations") limits SO_2 emissions to 0.5 parts per million (ppm) continuously for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Modeling results indicate that the maximum concentration of SO_2 released in one hour result in ground level concentrations less than 30 parts per billion (ppb). Section 302 ("General Emission Limitation") prohibits emissions from a gas stream containing SO_2 in excess of 300 ppm (dry). Expected emissions of sulfur dioxide are not expected to exceed 20 ppm.

Regulation 9, Rule 3, "Nitrogen Oxides from Heat Transfer Operations": Section 303 ("New or Modified Heat Transfer Operations") prohibits emissions in excess of 125 ppm of NO_x from any new heat transfer operation designed for a maximum heat input of 250 million Btu per hour or more.

Regulation 9, Rule 7, "Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters": Section 301 ("Emission Limits – Gaseous Fuel") prohibits NO_x in excess of 30 ppmvd at 3 percent O_2 and CO in excess of 400 ppmvd at 3 percent O_2. The duct burners after controls are expected to emit a maximum of 2.0 ppmvd of NO_x and 6 ppmvd of CO. These emissions are in compliance with this regulation.

Regulation 9, Rule 9, "Nitrogen Oxides from Stationary Gas Turbines": Regulation 9-9-301.3 limits NO_x emissions from stationary gas turbines to 9 ppmvd at 15 percent O_2. Each of the proposed combustion gas turbines are limited by CARB BACT guidelines to NO_x emissions of 2.0 ppmvd at 15 percent O_2. Therefore, the TPP turbines are expected to comply with the Regulation 9-9-301.3 NO_x limitation of 9 ppmvd at 15 percent O_2.

Table 5.2-5 summarizes the LORS.

The applicable LORS related to the potential air quality impacts from the TPP are described below. These LORS are administered (either independently or cooperatively) by the BAAQMD, U.S. Environmental Protection Agency (U.S. EPA) Region IX, the CEC, and the California Air Resources Board (CARB).

5.2.2 Affected Environment

This section describes the regional climate and meteorological conditions that influence transport and dispersion of air pollutants, as well as the existing air quality within the project region. The data presented in this section are representative of the TPP site.

The TPP site is located in the Alameda County, near the border with San Joaquin County. Nearby communities include Livermore (Alameda County) and Tracy (San Joaquin County). Although the area falls under the jurisdiction of the Bay Area Air Quality Management District, the project is located in the San Joaquin Valley Air Basin. The San Joaquin Valley is quite broad and is generally oriented north to south. The area surrounding the project site can be characterized as rural, being predominately undeveloped or farmland with small areas of

5.2.2.1 Climatology

The climate of the region, along with much of the West Coast of the country, is controlled by a semi-permanent high-pressure system that is centered over the northeastern Pacific Ocean. In the summer, the relatively northern location of this strong high-pressure system results in clear skies inland and coastal fog. During the summer, the project site typically experiences temperatures similar to inland areas. Very little precipitation occurs during the summer months because storm systems are blocked by the high-pressure system. Beginning in the fall and continuing through the winter, the high-pressure system weakens and moves south, allowing storm systems to move through the area. Temperature, winds, and rainfall are more variable during these months. The project site will receive an average of 14.5 inches of rain annually.

Long-term average temperature and precipitation data have been collected at the Tracy Carbona Station, the nearest surface meteorological station to the project site, and are presented in Table 5.2-6. The data indicate that July is usually the warmest month of the year, with a normal daily maximum temperature of 93.8°F, and a normal daily minimum of 56.8°F. In the fall and spring, the afternoon temperatures are mild, in the 60's and 70's, while nights are cooler, in the 40's and 50's. In the winter, temperatures are cool in the afternoon and crisp at night. The coldest month is usually January, with a normal daily maximum of 54.1°F and a normal daily minimum of 36.7°F.

Table 5.2-6. Temperature and Precipitation Data at the Tracy Carbona Station, San Joaquin, California

Month	Average Temperatures (°F) [a]		Average Precipitation (inches)
	Low	High	
January	36.7	54.1	1.93
February	40	61	1.71
March	42.5	66.7	1.41
April	45.6	73.4	0.84
May	50	80.6	0.5
June	54.8	88.1	0.09
July	56.8	93.8	0.03
August	55.6	92.4	0.09
September	53.9	87.9	0.24
October	48.7	78.6	0.53
November	42.1	64.9	1.13
December	36.6	54.7	1.49
Annual Average	46.9	74.7	9.99

Source: NWS, 2001.

Note:

[a]Average temperature and precipitation data represent 1948–2000.

Figures 5.2-2 through 5.2-5 present the predominant wind patterns occurring in California. As can be seen from Figure 5.2-2, the predominant regional surface winds during the winter are light and easterly. During the spring, summer, and fall the winds are stronger and westerly. These strong westerly winds are caused by the combination of high pressure offshore and a thermal low pressure resulting from high temperatures in the Central Valley. The quarterly windroses and stability tables from the TPP site are shown in Appendix K-2. The windrose shows that the predominant winds for the project site are persistent and from the southwest and west-southwest directions.

Atmospheric stability and mixing heights are important parameters in the determination of pollutant dispersion. Atmospheric stability reflects the amount of atmospheric turbulence and mixing. In general, the less stable an atmosphere, the greater the turbulence, resulting in more mixing and better dispersion. The mixing height, measured from the ground upward, is the height of the atmospheric layer in which convection and mechanical turbulence promote mixing. Good ventilation results from a high mixing height and at least moderate wind speeds within the mixing layer. Airflow in the San Joaquin Valley can be characterized by up-valley and down-valley winds. The down-valley winds are generally caused by airflows into the Valley from the Carquinez Strait and the Altamont Pass that then flow south. The horizontal transport of air in the project area is affected by strong diurnal wind regimes, and this results in a pronounced west-west-southwest component to the windrose.

5.2.2.2 Existing Air Quality

Ambient air quality standards have been set by both the federal government and the State of California to protect public health and welfare with an adequate margin of safety. Pollutants for which National Ambient Air Quality Standards (NAAQS) or State Ambient Air Quality Standards (SAAQS) have been set are often referred to as "criteria" air pollutants. The term is derived from the comprehensive health and damage effects review that culminates in pollutant-specific air quality criteria documents, which precede NAAQA and SAAQS standard setting. These standards are reviewed on a legally prescribed frequency and revised as new health and welfare effects data warrant.

Each NAAQS or SAAQS is based on a specific averaging time over which the concentration is measured. Different averaging times are based upon protection of short-term, high dosage effects or longer-term, low dosage effects. NAAQS may be exceeded no more than once per year. SAAQS are not to be exceeded.

The project site is in Alameda County but very close to the San Joaquin County border and the boundary between the San Francisco Bay Area and the San Joaquin Valley Air Basins. The ambient air quality in Alameda County is monitored at 6 permanent air monitoring stations. The monitoring station closest to the proposed project site is the Tracy-24371 Patterson Pass Road Station, in San Joaquin County. This monitoring station is located approximately 8 miles to the east of the project site. However, this station does not measure all criteria pollutant concentrations, and data from other stations are necessary. Monitoring stations at Stockton (San Joaquin County), Modesto (Stanislaus County), Fresno (Fresno County), and Bakersfield (Kern

County) are the nearest monitoring locations that are located in the same air basin as the project location and monitor most pollutants. Gaseous pollutants monitored at these stations include ozone, carbon monoxide, nitrogen oxides, sulfur dioxide and PM_{10}. Although Fresno and Bakersfield are quite far away, they are the closest monitoring station within the airshed that have ambient SO_2 data.

Air quality measurements taken at these stations are presented in Tables 5.2-7 through 5.2-11. For air quality impact analysis, the maximum background concentration from 1997 to 1999 from all monitoring stations was used. Data from 2000 was not used because the data for the entire year has not been posted yet.

The monitoring data shown in Tables 5.2-10 and 5.2-11 indicate that the air is in compliance with federal and California AAQS for NO_2 for all averaging periods at Stockton and Modesto monitoring stations and in compliance with all applicable SO_2 AAQS at Fresno. No SO_2 or NO_2 data were available at monitoring stations closer to the site.

Table 5.2-7 shows that the federal one-hour ozone AAQS of 0.12 ppm has been exceeded three of the last seven years at Tracy. The more stringent state ozone AAQS of 0.09 ppm was exceeded each year for the past seven years (and as many as 24 times in 1996).

The PM_{10} data in Table 5.2-8 show that the 24-hour average California AAQS of 50 $\mu g/m^3$ has been exceeded every year in San Joaquin County monitoring stations. The annual geometric mean is also called the state annual average and is a geometric mean of all measurements. The annual arithmetic mean is also called the national annual average and is an arithmetic average of the 4 arithmetic quarterly averages. The annual geometric and arithmetic mean concentrations frequently exceeded the California PM_{10} ambient air quality standard in both Stockton and Modesto. Except for 1991's data, these values are still below the federal PM_{10} AAQS of 50 $\mu g/m^3$.

The data in Table 5.2-9 show that maximum 8-hour average CO levels comply with the federal and California AAQS of 9.0 ppm. This limit has only been exceeded in 1991 in the last ten years.

Table 5.2-7. Ambient Ozone Levels near Tracy, 1991-2000 (ppm)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Tracy-24371 Patterson Pass Road, San Joaquin County.										
Maximum 1-Hour Average	--	--	--	--	0.124	0.140	0.119	0.116	**0.132**	0.122
Number of Days Exceeding California 1-Hour Standard (0.09 ppm)	--	--	--	--	9	24	5	14	16	7
Number of Days Exceeding Federal 1-Hour Standard (0.12 ppm)	--	--	--	--	0	2	0	0	1	0
Tracy-24081 Patterson Pass Road, San Joaquin County.										
Maximum 1-Hour Average	--	--	--	0.107	0.083	--	--	--	--	--
Number of Days Exceeding California 1-Hour Standard (0.09 ppm)	--	--	--	2	0	--	--	--	--	--
Number of Days Exceeding Federal 1-Hour Standard (0.12 ppm)	--	--	--	0	0	--	--	--	--	--
Maximum 8-Hour Average	--	--	--	0.087	0.069	--	--	--	--	--
Number of Days Exceeding Federal 8-Hour Standard (0.08 ppm) [a]	--	--	--	1	0	--	--	--	--	--

Note 1: Maximum average values ocurring during the most recent three years are indicated in bold.

Source: California Air Resources Board (CARB), 2001a, www.arb.ca.gov.

ppm = parts per million

Table 5.2-8. Ambient Particulate Levels (<10 μm) near Tracy, 1991-2000 (μg/m³)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Stockton-Hazelton Street, San Joaquin County										
Maximum 24-Hour Average	140	145	104	109	109	127	98	106	**150**	61
Annual Geometric Mean	43	39.9	32	32.6	23.8	23.7	26.8	24.4	**30.2**	24.9
Annual Arithmetic Mean	52.3	44.7	39.1	36.9	24.4	27.4	29.7	29.1	**36.4**	26.6
Estimated Number of Days Exceeding California 24-Hour Standard (50 μg/m³)	126	108	78	60	18	18	30	48	**60**	9
Stockton-Wagner-Holt School, San Joaquin County										
Maximum 24-Hour Average	--	--	--	--	--	117	**130**	99	118	64
Annual Geometric Mean	--	--	--	--	--	22.5	**22.5**	20.8	21.6	20.6
Annual Arithmetic Mean	--	--	--	--	--	29.2	**26.1**	25.5	22	22.6
Estimated Number of Days Exceeding California 24-Hour Standard (50 μg/m³)	--	--	--	--	--	6	24	**30**	24	12
Modesto-I Street, Stanislaus County										
Maximum 24-Hour Average	157	150	154	160	115	133	119	61	**132***	112*
Annual Geometric Mean	42.1	38.6	33.6	33.9	31.1	25.8	29.2	20.8	**33.6***	26*
Annual Arithmetic Mean	53.7	43.6	42	39.2	37.8	29.8	32.3	24.4	**40.9***	29.5*
Estimated Number of Days Exceeding California 24-Hour Standard (50 μg/m³)	144	108	96	66	84	18	42	12	**84***	24*

Note: Maximum average values occurring during the most recent three years are indicated in bold.

Source: California Air Resources Board (CARB), 2001a, www.arb.ca.gov.

-- = Data non available

* Data from Modesto-14th Street.

Table 5.2-9. Ambient Carbon Monoxide Levels near Tracy, 1991-2000 (ppm)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Stockton-Hazelton Street, San Joaquin County										
Maximum 1-Hour Average	14	11	10	10	10.3	9.4	7.7	**8.9**	8.3	5.8*
Maximum 8-Hour Average	11.38	7.38	6.25	6.89	4.5	6.41	3.6	**7.18**	5.34	3.59
Modesto-14th Street, Stanislaus County										
Maximum 1-Hour Average	19	10	11	9.5	11.4	9.2	7.1	9.4	**11.4**	6.2*
Maximum 8-Hour Average	10.75	6.5	8.63	6.35	5.74	6.46	4.99	**7.34**	6.36	4.17

Note: maximum average values occurring during the most recent three years are indicated in bold.

Source: California Air Resources Board (CARB), 2001a, www.arb.ca.gov.

ppm = parts per million

*Data cover only until October 2000.

**Data cover until November 1999.

Table 5.2-10. Ambient Nitrogen Dioxide Levels near Tracy, 1991-2000 (ppm)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Tracy-24371 Patterson Pass Road, San Joaquin County.										
Maximum 1-Hour Average [a]	--	--	--	--	0.068	0.061	0.06	**0.079**	0.074	0.068
Annual Average [b]	--	--	--	--	--	0.0132	0.0120	0.0133	**0.015**	--
Stockton-Hazelton Street, San Joaquin County										
Maximum 1-Hour Average [a]	0.11	0.19	0.16	0.144	0.119	0.088	0.09	0.102	**0.106**	0.099
Annual Average [b]	0.025	0.023	0.024	0.024	0.022	0.023	0.022	0.023	**0.024**	--
Modesto-14th Street, Stanislaus County										
Maximum 1-Hour Average [a]	0.11	0.1	0.11	0.093	0.093	0.087	0.093	0.088	**0.103**	0.079
Annual Average [b]	0.024	0.022	0.023	0.023	0.022	0.022	0.021	--	**0.022**	--

Note: Maximum average values occurring during the most recent three years are indicated in bold.

[a] All 1-hour concentrations are below the California NO_2 ambient air quality standard of 0.25 ppm

[b] All annual average concentrations are below the federal NO_2 ambient air quality standard of 0.053 ppm

Source: California Air Resources Board (CARB), 2001a, www.arb.ca.gov.

ppm = parts per million.

Table 5.2-11. Ambient Sulfur Dioxide Levels near Tracy, 1991-2000 (ppm)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Bakersfield, Chester Street and 5558 California Ave Stations [d]										
Maximum 1-Hour Average	0.03	0.03	0.03	0.02	0.026	0.059	**0.011**	--	0.01	
Maximum 24-Hour Average [b]	0.013	0.011	0.009	0.008	0.015	0.011	0.004	--	**0.006**	
Annual Average [c]	0.003	0.0016	0.0011	0.003	0.0028	0.0022	0.002	--	**0.003**	
Fresno-1st Street Station,										
Maximum 1-Hour Average [a]	--	--	--	--	--	--	--	--	--	--
Maximum 24-Hour Average [b]	0.013	0.010	0.010	0.011	0.010	0.009	0.003	--	--	--
Annual Average [c]	0.004	0.002	0.002	0.004	0.004	0.002	0.000	--	--	--

Note: Maximum average values occurring during the most recent three years are indicated in bold.

[a] No data was available at Fresno for the 1-Hour averaging period.

[b] All 24-hour average concentrations are below the California SO_2 ambient air quality standard of 0.04 ppm (105 μg/m^3) and the federal ambient air quality standard of 0.14 ppm (365 μg/m3).

[c] All annual average concentrations are below the federal SO_2 ambient air quality standard of 0.03 ppm (80 μg/m^3).

[d] Chester Street Station measured SO_2 until 1994, and California Ave Station measured from 1994 to 1999. There is no data for 1998 or 2000.

Source: California Air Resources Board (CARB), 2001a, www.arb.ca.gov.

ppm = parts per million

μg/m^3 = micrograms per cubic meter.

5.2.3 Best Available Control Technology

Federal requirements pertaining to control of pollutants subject to PSD review (i.e., attainment pollutants) were promulgated by U.S. EPA in 40 CFR 42.21 (j). This regulation defines BACT as emission limits "based on the maximum degree of reduction for each pollutant." BACT determinations are made on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs. Federal requirements pertaining to control of nonattainment pollutants, or Lowest Achievable Emission Rate (LAER), were promulgated by U.S. EPA under 40 CFR 51.165 (a). This regulation defines LAER as the emissions limit based on either (1) the most stringent emission rate contained in a State Implementation Plan, unless the [source] demonstrates the rate is not achievable; or (2) the most stringent emissions limitation that is achieved in practice. The federal LAER does not consider the cost impacts of control.

The BAAQMD defines BACT in Rule 2-2-206 as the most stringent emission limit or control technology that either:

1. Has been achieved in practice; or
2. Is contained in a State Implementation Plan approved by U.S. EPA unless demonstrated not to be achievable; or
3. Emission limits found by the Air Pollution Control Officer to be feasible and cost-effective for such class or category of sources or specific source.

The primary air emission sources for the proposed project are four parallel power generation trains. Each train consists of one natural-gas-fired "7FA" technology combustion turbine generator (CTG) set and a supplementary-fired HRSG. The steam produced by two HRSGs will be combined and sent to a steam turbine generator (STG). The proposed project will have four CTGs, four HRSGs, two STGs, and a nominal rating of approximately 1,120 MW.

Applicable BACT levels are shown in Table 5.2-12. BAAQMD Rule 2-2-206 requires the proposed project to apply BACT if the project's emission levels are in excess of the applicability levels shown in the table. The criteria air pollutants to be emitted at the HRSG stacks include NO_X, CO, PM_{10}, SO_2 and VOCs (or POCs). Given these thresholds, BACT will be required for NO_X, POC, PM_{10}, SO_2, and CO emissions control for the proposed project.

Table 5.2-12. Applicable Best Available Control Technology Levels

Pollutant	Significant Thresholds (lbs per highest day)
POC (VOC or NPOC)	10
NO_X	10
SO_2	10
PM_{10}	10
CO	10

Notes:
CO = carbon monoxide
NO_X = nitrogen oxides
NPOC = non-precursor organic compounds
PM_{10} = particulate matter less than 10 microns in diameter
POC = precursor organic compounds
SO_2 = sulfur dioxide
VOC = volatile organic compounds

In addition to the power generation train, an emergency generator, a diesel fire water pump engine, and a cooling tower will also be air emission sources on the site. The 735-kW emergency generator and the 250-kW diesel firewater pump will operate approximately 100 hours per year. The emergency generator will emit NO_x at levels above the 10 pound per day level requiring BACT. The diesel firewater pump will not trigger BACT for any constituent. The cooling tower will emit PM_{10} at levels above the 10 pound per day level requiring BACT.

5.2.3.1 BACT Assessment for CTG/HRSG

The project proposes for NO_X control the use of dry low-NO_X (DLN) combustors and SCR with ammonia injection designed to achieve a NO_X emission limit of 2.0 ppmvd (at 15 percent O_2) for a 3-hour average.

Other technologies have either not achieved a NO_X level of 2.0 ppm (at 15 percent O_2) in practice for gas turbines of a similar size to that proposed for the TPP project, or offer equivalent NO_X control efficiency with other less desirable features. Also, the project proposes a CO emission limit of 6.0 ppmvd for a 3-hour average with an oxidation catalyst as a post-combustion control technology. The remainder of this section contains the BACT analysis conducted for the proposed project, and demonstrates that the proposed CTG controls summarized in Table 5.2-13 comply with BACT requirements.

Table 5.2-13. Summary of Tesla Power Project Best Available Control Technology

Pollutant	Control Technology	Concentration ppm @ 15% O_2 dry
NO_X	Dry low-NO_X combustors and SCR with ammonia injection	2.0
CO	Catalytic oxidation	6.0
POC	Catalytic oxidation	< 2.0
SO_X	Pipeline quality natural gas	< 0.2
PM_{10}	Pipeline quality natural gas	Not Applicable

Notes:
CO = carbon monoxide
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
POC = precursor organic compounds
SO_X = sulfur oxides

BACT Assessment Methodology

The BACT assessment conducted for the CTGs proposed for the project considered all NO_X and CO control technologies currently proposed or in use on large natural gas–fired combustion turbines (>50 MMBtu/hr heat input). To identify feasible emission limits, several information sources were consulted, including the following:

- U.S. EPA's BACT/LAER Clearinghouse and updates;
- CARB's BACT Clearinghouse database and CARB's BACT Guidelines for Power Plants (adopted 7/22/99);
- BAAQMD BACT Guidelines Manual;
- South Coast Air Quality Management District (SCAQMD) BACT Guidelines Manual;
- Discussions with permitting staff from U.S. EPA Region IX;
- Recent CEC Applications for Certification; and
- Research conducted by TPP project design engineers.

Table 5.2-14 lists selected recent NO_X BACT proposals and determinations for natural-gas-fired advanced technology combustion turbines similar in size to the TPP CTGs. A NO_X emission rate of 2.5 ppmvd (at 15 percent O_2) on a 3-hour average has been routinely required of recent projects. A concentration of 2.0 ppmvd represents the lowest permitted level to date that has been achieved in practice for large turbines.

Table 5.2-14. Summary of Recent NO_x Best Available Control Technology Determinations for Combustion Turbine Generators Rated Greater than 50 MW

Name	Location	Rating (MW)	Vendor, Model	Emission Limit[a]	Control(s)	Permit Date
Contra Costa	CA	530	GE 7FA	2.5 ppmvd	DLN with SCR	5/01
Pastoria	CA	750	F-Class	2.5 ppmvd	DLN with SCR or XONON (demonstration)	12/00
Pittsburg	CA	500	GE 7FA	2.5 ppmvd	DLN with SCR	8/99
Delta	CA	200	GE 7251FA	2.5 ppmvd	DLN with SCR	2/00
Midway Sunset	CA	500	GE 7F or Westinghouse 501F	2 ppmvd	SCR	3/01
Blythe	CA	520	GE 7F or Westinghouse 501F	2.5 ppmvd	SCR	3/01
Mountainview	CA	1,034	GE 7FA	2.5 ppmvd	DLN with SCR	3/01
Otay Mesa	CA	510	GE 7F or Westinghouse 501F	2.5 ppmvd	DLN with SCR or SCONOx	4/01
Three Mountain	CA	500	GE 7F or Westinghouse 501F	2 ppmvd	DLN with SCR	5/01
Sunrise	CA	165	GE 7FA	9 ppmvd	DLN (simple cycle)	12/00
Elk Hills	CA	500	GE 7FA	2.5 ppmvd	DLN with SCR	12/00
La Paloma	CA	172	GE 7FA or ABB KA-24	2.5 ppmvd	DLN and SCR	10/99
High Desert	CA	330	GE 7F	2.5 ppmvd	SCR	5/00
Sutter	CA	170	GE 7F or Westinghouse 501F	2.5 ppmvd	DLN and SCR	4/99

Notes:

[a] Based on 3-hour average.

DLN = Dry low NO_X combustor

ppm = Parts per million by volume, dry basis, at 15% oxygen

SCR = Selective catalytic reduction

TBD = To be determined

U.S. EPA Region IX, CARB, and SCAQMD guidance stipulate a BACT emissions limit for NO_X of 2.5 ppmvd (at 15 percent O_2) for a 1-hour average. U.S. EPA and CARB stipulate 2.0 ppmvd (at 15 percent O_2) for a 3-hour average.

NO_X Control Technologies

Based on a review of materials described above, the following NO_X control technologies were evaluated to determine whether they are able to achieve BACT NO_X levels in practice:

- DLN and XONON™;
- DLN and Goal Line SCONOx™;
- DLN and SCR with ammonia injection.

XONON™. The XONON™ combustion system improves the combustion process by lowering the peak combustion temperature to prevent the formation of NO_X while avoiding the increases in CO and unburned hydrocarbons (UHC) associated with other NO_X control technologies (such as water injection and DLN). Most gas turbine emission control technologies remove air contaminants from exhaust gas prior to release to the atmosphere. In contrast, the overall combustion process in the XONON™ system is a partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. In the catalyst module a portion of the fuel is combusted without a flame (i.e., at relatively low temperature) to produce a hot gas. A homogeneous combustion region is located immediately downstream where the remainder of the fuel is combusted.

The key feature of the XONON™ combustion system is a proprietary catalytic component, called the XONON™ Module, which is integral to the gas turbine combustor. XONON™ combusts the fuel without a flame, thus eliminating the peak flame temperatures that lead to NO_X. Turbine performance is not affected.

XONON™ is an innovative technology that is currently being commercialized on smaller-scale projects with support from the U.S. Department of Energy, California Energy Commission, and the CARB. The CARB has reported on the pilot effort underway in Santa Clara where the XONON™ system is operating at a 1.5 MW simple-cycle pilot facility. The CARB indicated in their June 1999 Stationary Source Division Report *Guidance for Power Plant Siting and Best Available Control Technology,* page 23: "Emission levels from 1.33 to 4.04 ppmvd NO_X at 15 percent oxygen (O_2) have been achieved at Silicon Valley Power utilizing the XONON™ technology." But they further indicate "there is not sufficient operating experience to ensure reliable performance on large gas turbines."

XONON™ has been proposed as a demonstration technology on a GE F-Class turbine for the Pastoria AFC. The Pastoria Final Determination of Compliance (FDOC) provides provisions to use SCR if XONON™ is unavailable or unusable. General Electric has indicated to that applicant that XONON™ technology will not be available for their large combustion turbines, such as the Frame 7FA, for another 5 to 7 years, and therefore would not be available to support this project. Because XONON™ is not currently commercially demonstrated technology for the General Electric Frame 7FA combustion turbine model and it has received very limited trial operation only on much smaller CTG units, XONON™ is not considered as a viable NO_X emissions control option for TPP.

SCR versus SCONOx. Of the current NO_X control technologies, DLN and SCR with ammonia injection, and DLN and SCONOx are considered the two technologies that could potentially achieve the proposed BACT NO_X level of 2.0 ppmvd (at 15 percent O_2), 3-hour average. These two technologies were evaluated further to determine whether they are technically feasible alternatives and could be considered achieved in practice for the proposed gas turbines. Other technologies, such as either SCR or DLN alone, or steam injection, have not achieved such low NO_X levels in practice for gas turbines of a similar size to those proposed for the TPP.

SCONOx, produced by Goal Line Environmental Technologies, is a new technology for reducing both NO_X and CO from gas turbines. SCONOx has been reported to have achieved NO_X emission concentrations as low as 2 ppm, while also achieving 90 percent CO reduction. The system consists of a catalyst installed in the flue gas at a point where the temperature is between 600°F and 700°F. SCONOx is a rather complex abatement process. It is a five-step batch process, whereas SCR is a continuous, single-step process. The five steps for SCONOx include:

1. Conversion of NO_X to NO_2 and subsequent absorption onto the SCONOx catalyst, yielding potassium nitrate and potassium nitrite (this process exhausts the SCONOx catalyst);
2. The exhausted catalyst is isolated by sealing dampers. This catalyst in the isolated area is regenerated in an oxygen-free environment consisting of a mixture of hydrogen gas and carbon dioxide. The regeneration process converts the potassium nitrate and potassium nitrite (formed in the first step) to elemental nitrogen and water;
3. The regeneration gases (hydrogen and carbon dioxide) are formed from natural gas and steam in the presence of another catalyst. The catalyst used in this step is poisoned by the presence of sulfur;
4. The natural gas used in the previous step is stripped of sulfur to prevent poisoning the catalyst described in step 3 using the SCOSOx technology; and
5. The final step is the regeneration of the SCOSOx catalyst. This regeneration process is similar to the process described in step 2 (CEC, 2000).

The system does not use ammonia as a reagent. CO emissions are reduced by the oxidation of CO to CO_2.

Only two SCONOx systems have been installed. The largest system has operated at the Federal Paperboard Plant owned by Sunlaw Cogeneration since December 1996. The unit is an LM2500 gas turbine and is approximately 32 MW in capacity, roughly one-fifth the capacity of the GE Frame 7FA combustion turbine. However, it operates at a significantly lower temperature than the system would at a combined cycle project employing a Frame 7 type machine with the SCONOx device incorporated into the HRSG.

The only system operating at this higher temperature, a 5 MW machine operating at the Genetics Institute in Massachusetts has not passed its compliance tests. The original permit received by Genetics Institute from the Massachusetts Department of Environmental Protection (DEP) recognized the demonstration nature of the SCONOx technology by provisionally allowing up to 18 months of operation before the SCONOx system was required to demonstrate continuous compliance with a NO_X emission limit of 2.5 ppmvd. The 18-month period ended on November 4, 2000 without Genetics Institute being able to make this demonstration. Therefore, Genetics Institute applied for and received from DEP an 18 month extension of the provisional period. The subsequent 18 month period will allow Genetics Institute, Goal Line and Solar Turbines additional time to attempt to bring the system into compliance with the NO_X emission limit (McGinnis, 2001).

Potential advantages of the SCONOx process include wide operating temperature flexibility and, simultaneous CO emission reduction. In addition, SCONOx does not use ammonia, eliminating the ammonia storage and transportation safety issues and the potential for ammonia slip or ammonia-based particulate formation.

SCONOx has some major disadvantages. The technology is being offered at substantially higher capital cost than SCR. Replacement of the SCONOx precious metal catalyst is also more expensive than SCR. Finally, the on-line catalyst washing system has not been adequately demonstrated on a commercial basis and there is no experience on Frame F-sized gas turbines. Problems with the reliability of the required damper system and with flow distribution have also been reported. Only very recently has the technology been made "commercially" available by ABB. However, it remains unclear whether the "commercial" guarantees being offered are adequate. Because the low NO_X emission rates attainable on smaller turbines with SCONOx have not been "achieved in practice" on F-sized turbines, the technology does not represent BACT for F-sized turbines at this time. Based upon extensive testimony on the issue, the final decision issued by the CEC in the Elk Hills Power Project proceeding found that SCONOx was not yet demonstrated, having experienced significant scale-up problems (99-AFC-1, December 2000). Two other applications have proposed to employ SCONOx. One is proposed for the Otay Mesa Project as a demonstration. If SCONOx does not work, provisions in the Determination of Compliance would allow SCR to be installed. The project is proposed to be permitted at 2.5 ppmvd NO_X. The second project is Nueva Azalea (00-AFC-3), which had been proposed by Sunlaw Corporation. Sunlaw has a proprietary interest in the SCONOx technology. That AFC was suspended on March 12, 2001. A detailed cost effectiveness comparison looking at both the capital and operating costs of the SCONOx system and the SCR/CO catalyst system is shown in Table 5.2-15. The comparison for SCONOx shows that it is not cost effective compared to SCR in this circumstance.

On the other hand, SCR with ammonia injection systems for reduction of NO_X emissions have been widely used in CTG/HRSG applications for many years. It is considered a proven technology and is commercially available from several vendors. The SCR process involves a one-stage process of injection of ammonia into the flue gas upstream of a catalyst. The ammonia reacts with NO_X in the presence of the catalyst. The catalyst is not regenerated and requires periodic replacement, typically every three years. SCR with ammonia injection has been used in numerous CTG/HRSG applications up to and including F Class units.

DLN combustion is a system design employed by several major turbine vendors. Virtually all gas turbine manufacturers are continuing to research and improve on these advanced combustion technologies because they represent the most cost-effective NO_X reduction approach. The source of NO_X emissions from natural gas turbines is the thermal NO_X formation reaction, which is very dependent on combustor design. This reaction converts natural atmospheric nitrogen and oxygen to NO_X at the high temperatures of combustion. DLN combustion results in turbine exhaust NO_X emission rates of 25 ppmvd (at 15 percent O_2) or less.

As noted in Table 5.2-14, for large turbines that are similar in capacity to the TPP turbines, DLN and SCR have been permitted at NO_X emissions of 2.5 ppmvd (at 15 percent O_2). Thus, DLN with SCR with ammonia injection, designed to achieve a NO_X emission limit of 2.0 ppmvd (at 15 percent O_2) on a 3-hour average, is considered BACT.

CO Control Technologies

CO emissions from the CTGs/HRSGs will be controlled by the use of post-combustion oxidation catalysts to be located in the HRSGs. The TPP CTGs/HRSGs with CO oxidation catalyst are guaranteed to achieve 6.0 ppmvd (at 15 percent O_2) on a 3-hour average, except during startup and shutdown. A review of recent BACT determinations in Table 5.2-16 indicates that the CARB BACT guideline CO emission limit of 6 ppmvd (at 15 percent O_2) has been required of many recent projects. Although Three Mountain, High Desert, and Sutter were all permitted at 4 ppmvd and Otay Mesa was permitted at 2 ppmvd, these emission levels have not been proven in practice. Midway Power, LLC, requests 6 ppmvd as the BACT level for CO for the TPP, which is consistent with BAAQMD BACT guidelines. The proposed BACT limit for the TPP CTGs/HRSGs more than satisfies the BACT requirements. CO oxidizing catalysts have been used with natural gas fired turbines for over a decade. CO catalysts operate at elevated temperatures within the HRSG.

VOC (POC) and PM_{10} Control Technologies

A summary of recent BACT determinations is provided in Table 5.2-16. The proposed TPP BACT level of 1.1 ppmvd (at 15 percent O_2) for VOC control with effective combustion conforms to CARB guidelines. The TPP turbines are not expected to exceed 2.0 ppmvd VOC when the duct burners are firing. The TPP VOC emissions are consistent with those of other recent projects. PM_{10} emissions will be controlled through the use of clean burning pipeline quality natural gas.

5.2.3.2 Assessment of BACT for Emergency Generator

The TPP will use an emergency diesel-fired generator rated at 735 kW. Historical BACT determinations and other feasible technologies available for emergency diesel engines were reviewed for diesel driven emergency generators rated greater than 400 hp. To be consistent with CARB and BAAQMD BACT guidelines, a NO_x emission level of less than 6.9g/bhp-hr will be specified for the emergency generator. Control of SO_2 and PM_{10} emissions will be achieved by firing with low-sulfur (less than 0.05% by weight) diesel fuel in this application. These emission levels are considered BACT.

5.2.3.3 Assessment of BACT for Cooling Tower

After review of the U.S. EPA's RBLC database and other BACT databases, it was determined that the only technology used to limit particulate emissions from cooling towers is the use of drift eliminators. High-efficiency drift eliminators, which allow less than a 0.0005% drift rate, will be used on the cooling tower in this application as BACT. This is consistent with the BACT determinations of other recent CEC projects.

Table 5.2-16. Summary of Recent Combustion Turbine CO and VOC BACT Determinations

Project Name	State	Date	Rating (MW)	CO BACT Level, ppmvd (at 15% O_2)	VOC BACT Level, ppmvd (at 15% O_2)
Contra Costa	CA	5/01	2-170	6.0	2.0
Pastoria	CA	12/00	3-168	6.0	2.0
Pittsburg	CA	8/99	2-170	6/9[a]	NA
Delta	CA	2/00	3-200	10.0	2.0
Midway Sunset	CA	3/01	2-170	6.0	2.0
Blythe	CA	3/01	2-170	5.0	1.0
Mountainview	CA	3/01	4-167	6.0	1.4
Otay Mesa	CA	4/01	2-170	2.0	2.0
Three Mountain	CA	5/01	2-170	4.0	2.0
Sunrise	CA	12/00	2-165	9.0	1.2
Elk Hills	CA	12/00	2-165	6.0	2.0
La Paloma	CA	10/99	4-172	6.0	0.4
High Desert	CA	5/00	2-330	4.0	1.0
Sutter	CA	3/99	2-170	4.0	1.0

Source: CEC, 2001.

[a] CO emission limit increases from 6 to 9 ppm at reduced load.

5.2.3.4 Fugitive Dust Control

Other controls that will be implemented at the TPP site include best achievable control measures (BACM) during construction. Fugitive dust control measures include the following:

- Use, where possible, of water or chemicals for control of dust construction operations, the construction of roadways or the clearing of land; and
- Application of asphalt, oil, water, or suitable chemicals on dirt roads, materials stockpiles, and other surfaces that can give rise to airborne dusts.

The TPP proposes to use the following fugitive dust suppression program to reduce construction-related emissions. Fugitive dust emissions are expected to be reduced by ninety percent. The use of chemical additives is not planned.

- Frequent watering of unpaved roads and disturbed areas (at least twice a day).
- Limit speed of vehicles on the construction areas to no more than 10 miles per hour.
- Sweep paved internal roads after the evening peak period.
- Increase frequency of watering when wind speeds exceed 15 miles per hour.
- Employ tire washing and gravel ramps prior to entering a public roadway to limit accumulated mud and dirt deposited on the roads.

- Treat the entrance roadways to the construction site with soil stabilization compounds.
- Place sandbags adjacent to roadways to prevent run-off to public roadways.
- Install windbreaks at the windward sides on construction areas prior to the soil being disturbed. The windbreaks shall remain in place until the soil is stabilized or permanently covered.
- Employ dust sweeping vehicles at least twice a day to sweep public roadways that are used by construction and worker vehicles.
- Sweep newly paved roads at least twice weekly.
- Replace ground cover in disturbed areas as quickly as possible.
- Cover all trucks hauling dirt, sand, soil or other loose materials and maintain a minimum of six inches of freeboard between the top of the load and the top of the trailer.
- Limit on equipment idle times (no more than fifteen minutes.)
- Employ electric motors for construction equipment when feasible.
- Apply covers or dust suppressants to soil storage piles and disturbed areas that remain inactive for over two weeks.
- Pre-wet the soil to be excavated during construction.

Designate a person to oversee the implementation of the fugitive dust control program.

5.2.4 Environmental Consequences

This section describes the analyses conducted to assess the potential air quality impacts from the TPP. Emissions estimates are presented for construction and operation of the TPP. Dispersion model selection and setup are also described (i.e., emissions scenarios and release parameters, building wake effects, meteorological data, and receptor locations) and results are presented for the dispersion modeling. In addition, results are presented for the visibility modeling.

5.2.4.1 Construction Emissions

The primary emission sources during construction will be heavy equipment and fugitive dust from disturbed areas resulting from site construction, gas line construction, water line construction, and transmission line construction. A particulate matter emission factor of 0.11 tons of PM_{10} per acre per month was used to estimate fugitive dust emissions (MRI, 1996). The following amounts of acreage are expected to be disturbed during construction:

- Months 1–5: 41 acres (40 acres on-site);
- Months 6–14: 91 acres (43.5 acres on-site); and
- Months 15–23: 41 acres (40 acres on-site).

Based on this construction schedule, the worst-case construction emissions will occur between the sixth and fourteenth month of construction when 91 total acres of land are disturbed and 43.5 acres are disturbed on-site. This results in uncontrolled emissions of approximately 10.01 tons of PM_{10} per month total and 5.63 tons/month on-site. Assuming 90% control efficiency from frequent water applications on active construction surfaces during hours of construction (or other equivalent dust suppression measures; see Section 5.2.3 for details on fugitive dust control measures), the controlled worst-case construction dust emissions are estimated to be 1.0 tons/month and 0.48 tons/month on-site. Annual average fugitive dust emissions are estimated to be approximately 0.86 tons/month on-site, based on the average disturbed land acreage listed above for months 3 through 14 and assuming the same fugitive dust emission factor and control efficiency.

Another source of emissions during construction will be equipment exhaust. Equipment-specific emission factors were used to estimate emissions for all criteria pollutants (U.S. EPA, 1991). Table 5.2-17 presents a list of equipment anticipated during construction, including the estimated numbers of each equipment type that are expected to operate during each month of construction. Emissions from equipment will occur over a 23-month construction period. Tables 5.2-17a and 5.2-17b present data similar to Table 5.2-17 for equipment expected to be used for off-site construction activities.

The worst-case hourly, monthly, and annual emissions for on and off-site construction are presented in Tables 5.2-18a and 5.2.18b. Construction emission calculations are provided in Appendix K-3.

Table 5.2-18a. Estimated Criteria Pollutant Emissions from Construction Activity

	NO_x	CO	VOC	SO_x	PM_{10} [a]
Worst-Case Monthly Emissions (lbs/month)	11525.7	5356.8	1476.1	1113.7	240.9
Worst-Case Hourly Emissions (lbs/hr)[b]	48.0	22.3	6.2	4.6	10.0
Worst-Case Annual Emissions (tons/yr)[c]	53.35	26.4	7.0	5.26	12.26

[a] PM_{10} emissions include construction equipment and fugitive dust.

[a] Worst-case hourly emissions were estimated by dividing worst case monthly emissions by 240 hours. Total emissions were based on projected daily hours of equipment operation in a given month. Daily average hours of operation are shown in Appendix K-3.

[b] Worst case annual emissions were estimated by summing emissions for each 12 month period (i.e., months 1-12, 2-13, etc.) during the 23 month construction period and taking the maximum emissions for the worst 12-month period (i.e., month 2-13 for CO, VOC, SO_X, and PM_{10} and month 5-16 for NO_X).

Table 5.2-18b. Estimated Criteria Pollutant Emissions from Off-Site Construction Equipment

	NO_x	CO	VOC	SO_x	PM_{10}
Worst-Case Monthly Emissions (lbs/month)	26,438	11,411	2,983	2,717	2,557
Worst-Case Hourly Emissions (lbs/hr)[a]	109.25	7.2	12.3	11.2	10.6
Worst-Case Annual Emissions (tons/yr)	29.0	11.8	3.2	2.9	2.7

[a] Worst-case hourly emissions were estimated by dividing worst case monthly emissions by 242 hours. Total emissions were based on projected daily hours of equipment operation in a given month. Daily average hours of operation are shown in Appendix K-3.

5.2.4.2 Operational Emissions

Operational emissions from the four turbines were estimated for all applicable scenarios using base emission rates and startup/shutdown emissions. It was conservatively estimated that there would be 12 cold startups, 6 warm startups, 27 hot startups, and 45 shutdowns per year for each generating set. Each generating set includes two gas turbines, two heat recovery steam generators and one steam turbine. Annual operating conditions are shown in the Table 5.2-19. The base criteria pollutant emission rates provided by the turbine vendor for three load conditions (50%, 75%, and 100%) and four ambient temperatures (17°F, 62°F, and 112°F) are presented in Table 5.2-20. Because startup and shutdown events typically had higher emission rates than operating conditions, they were incorporated into the short- and long-term emissions estimates for each turbine for modeling purposes. The expected emissions and duration of startup events are summarized in Table 5.2-21. These worst-case emission estimates are included in Appendix K-4.

NO_x and CO emission rates for the 1-hour worst-case scenario were estimated using the cold startup maximum emission rate and warm startup maximum emission rate, respectively, because they are the highest hourly emission rate. The worst-case SO_2 1-, 3-, and 24-hour emission rates were estimated using the operating emission rate because SO_2 is solely a function of fuel consumption rate. The maximum CO emission rate for the 8-hour scenario was estimated assuming one warm startup with the remaining scenario time (i.e., 5 hours) at maximum normal operating load (17°F; 100% load, with duct burners on) because this scenario emits the highest CO emission rate for an 8-hour period and is operationally realistic.

Table 5.2-21. Criteria Pollutant Emission Rates for the Turbines During Startup[a]

Pollutant	Cold Startup 300 minutes		Warm Startup 180 minutes		Hot Startup 90 minutes	
	Max lb/hr	Total lb/300 min	Max lb/hr	Total lb/180 min	Max lb/hr	Total lb/90 min
NO_X	300	831	263	451.6	219	232.4
CO	800	1802.9	1325	2360.5	700	711.8
VOC	64	165.9	90	158	70	70.6
SO_2	4.02	20.01	4.02	12.06	4.02	6.04
PM_{10}	25.5	127.5	25.5	76.5	25.5	38.25

a Emissions include two turbines in startup mode.

To calculate annual emissions, emissions from the startups were added to operational emissions, assuming 100 percent load and 60°F for the specified number of hours per year and duct burner operation at 60°F for the specified number of hours. The analysis is conservative because no credit was taken for estimated downtime associated with each shutdown. Estimated annual emissions for the four turbines are presented in Table 5.2-22. Emissions and calculations for all scenarios are contained in Appendix K-4.

Table 5.2-22. Annual Turbine/HRSG Emissions (all four turbines/HRSG)

Pollutant	Duct Burner Off (lbs)	Duct Burner On (lbs)	Startup (lbs)	Annual Emissions (lbs/yr)	Annual Emissions (tpy)[a,b]
NO_x	143,461	309,133	37,913	490,507	245.3
CO	262,036	564,640	110,033	936,709	468.4
VOC	23,421	84,695	9,690	117,806	58.9
PM_{10}	109,643	264,731	4,640	379,015	189.5
SO_2	18,410	39,739	779	58,928	29.5

a Includes emissions from all four turbines/HRSGs.

b Emissions include 12 cold startups, 6 warm starts, and 27 hot startups, and 5,260 hours at 100% duct burner capacity with the balance of the time operating at 100% load at 62°F. See Table 5.2-19 for details.

Worst-case short-term emissions from the turbines were calculated for use in the air quality modeling. For worst 1-hour emissions, the worst-case startup condition for all four turbines was used. Based on the startup information, NO_x emissions during a cold startup is the worst case condition for NO_x. Emissions during a warm startup is the worst-case condition for CO and VOC. PM_{10} and SO_x emissions are directly proportional to fuel usage. The maximum amount of fuel is used when the turbines and duct burners are running 100% and the ambient temperature is 17°F.

The 3-hour SOx emission rate was used using the scenario when all four turbines and duct burners are running 100% and the ambient temperature is 17°F. The 8-hour CO emission rate was calculated assuming one full warm start and the balance (5 hours) operating at the worst-case operating condition (all four turbines and duct burners are running 100% and the ambient temperature is 17°F).

The 24-hour NO_x emission rate was calculated assuming one cold start and the balance (19 hours) operating at the worst-case operating condition (all four turbines and duct burners are running 100% and the ambient temperature is 17°F). Likewise, the CO and VOC 24-hour emission rates were calculated assuming one warm start and the balance (21 hours) operating at the worst-case operating condition (all four turbines and duct burners are running 100% and the ambient temperature is 17°F). PM_{10} and SO_x worst-case 24-hour emission rates were calculated assuming all four turbines and duct burners are running 100% and the ambient temperature is 17°F for 24 hours.

Worst-case short-term emissions are shown in Table 5.2-23.

Table 5.2-23. Short-term Emission Estimates (four turbines)

1-Hour Emissions (lbs/hr)		
	NO_x	600
	CO	2652
	VOC	180
	PM_{10}	51.0
	SO_2	8
3-Hour Emissions (lbs/hr)		
	SO_2	8
8-Hour Emissions (lbs/hr)		
	CO	661.6
24-Hour Emissions (lbs/day)		
	NO_x	2853.2
	CO	7125.6
	VOC	673.6
	PM_{10}	1224.0
	SO_2	192.8

Cooling Tower. Particulate matter emissions from the cooling tower were based on an analysis of the concentration of the total dissolved solids (TDS) in the cooling water and a drift rate of 0.0005%. Two studies were reviewed to find the droplet size distribution from cooling towers in order to determine the fraction of particulate matter emitted could be classified as PM_{10}. Midway Power, LLC received data from Brentwood Industries, a drift eliminator manufacturer, on water droplet size distribution. This study indicated that 24% of particulate matter emitted could be classified as PM_{10}. Another study performed by Ecodyne Cooling Products concluded that only 31.3% of all particulate matter emitted would disperse into the atmosphere. This study indicated that this includes all particulate matter less than 100 microns in diameter. The larger particulate matter fraction (31.3%) was used to determine the portion of total particulate matter emitted from the cooling tower than can be characterized as 10 microns or less in diameter. This analysis is shown in Appendix K-4. Table 5.2-24 shows the estimated cooling tower emissions.

Table 5.2-24. Emissions from Cooling Tower

Water Rate	296,220 gpm	
Drift Rate	0.0005%	
Number of Cells	22	
Maximum TDS	6000 lb/MMlbs (ppmw)	
PM_{10} Mass Fraction	31.3 %	
	lb/hr/cell	g/s/cell
PM_{10}	0.0633	0.00798

Diesel IC Engines. The TPP will include a 735 kW emergency diesel generator and 274 kW fire water pump engine that will operate for 30 minutes every two weeks for reliability confirmation. Emissions were estimated based on hourly emission rates provided by the manufacturer for NO_x, CO, PM_{10} and VOC. SO_2 emissions were estimated using an emission factor for stationary diesel engines from U.S. EPA AP-42 Section 3.3. Annual emissions from the engines included in the TPP summary in Table 5.2-25 are based on 50 hours of operation per year. Emissions and calculations for engines are included in Appendix K-4.

5.2.4.3 Commissioning Activities and Emissions

During the commissioning phase, the equipment is tested to ensure that it is working according to specification and that plant interconnections were adequately installed. The initial commissioning phase from first fire to performance testing is sequenced in the following manner:

1. First Fire
2. Rough Dry Low NO_x (DLN) combustor Tuning: The CTGs will be gradually raised to full load while monitoring with the installed CEMS using GE certified gases. Usually 3 to 4 days (12 hours per day) for each gas turbine.
3. Steam blows: Operation of the gas turbines up to 50 MW's is required to generate sufficient steam production for cleaning steam lines. Duration - one week (24 hours per day) for power block with both gas turbines in service.
4. The SCR catalyst will be installed into the HRSG's SCR section. This work will be done concurrently with the steam blow restoration outage.
5. Fine DLN tuning: The CTGs will be loaded incrementally to full load to adjust for optimum combustion and efficiency. A certified emissions laboratory trailer will be on site to support this tuning as well as begin the CEMS certification process. This process may take as much as four weeks (12-16 hours per day).
6. The CTGs will be fired to support steam turbine commissioning. The CTGs will be operated at varying load to achieve steam conditions required for steam turbine commissioning. Most likely this will be done while CEMS certification is in progress. The steam turbine commissioning normally requires 14 days (12-16 hours per day).
7. The SCR commissioning will be occurring simultaneously with steps 5 and 6 above.
8. The final plant tuning to adjust controls of the CTGs and STGs. Four (4) weeks duration (12 –24 hours per day); the emissions equipment should be certified prior to completion of this activity.

The first four tests itemized above typically each take a day or less to complete. The DLN tune may take up to three days. The last two tests may be run simultaneously and typically last about two weeks. In addition, the combustion turbines will be run during the commissioning of both HRSGs and the steam turbine. The duration of all tests may be affected by unforeseen events and therefore are only estimates. A maximum of 500 hours of operation during commissioning of each combustion turbine is expected over a period not to exceed five months. A minimum of one turbine start would be needed for each test. Additional starts may be necessary.

There are two high emissions scenarios possible during commissioning.

Scenario 1: The first scenario would be the period prior to SCR system and oxidation catalyst installation, when the combustor is being tuned. Under this scenario, NO_x emissions would be high because the NO_x emissions control system would not be functioning and because the combustor would not be tuned for optimum performance. NO_x emissions can be conservatively estimated to be twice the guaranteed turbine-out level of 9 ppmvd @ 15 percent O_2, or 18 ppm. If operation under this condition were to continue for one hour, maximum hourly NO_x emissions at full load would be (18 ppm/2 ppm) * 15.67 lbs/hr = 141.03 lbs/hr. CO emissions would also be high because combustor performance would not be optimized and the CO emissions control system would not be functioning. CO also can be estimated at twice the highest expected turbine-out level of 10 ppm, or 20 ppm. Maximum hourly CO emissions under this scenario would thus be (20 ppm/6 ppm) * 28.62 lb/hr, or 95.4 lb/hr.

Scenario 2: The second high emissions scenario would occur when the combustor has been tuned but the SCR and oxidation catalyst installation is not complete, and other parts of the turbine operating system are being checked out. Since the combustor would be tuned but the control system installation would not be complete, NO_x and CO levels would again be high. Under these lower load conditions, NO_x emissions could be as high as 36 ppm @ 15 percent O_2. Based on the transient nature of the loads, the average fuel consumption would be expected to be equivalent to half the full load flow rate, or 844 MMBtu/hr. Worst-case hourly NO_x emissions under this scenario would be (36 ppm/2 ppm) * 8.64 lbs/hr = 155.5 lbs/hr. CO emissions under these conditions would be expected to be the same as those calculated for Scenario 1.

Because the higher NO_x emissions would occur under Scenario 2, and NO_2 impacts could be higher than under other operating conditions already evaluated, these emissions were used to determine the air quality impacts due to commissioning activities. The results of this analysis are shown in Section 5.2.4.7.

5.2.4.4 Air Dispersion Modeling

The purpose of the air dispersion modeling analysis is to demonstrate that air emissions from the TPP will not cause or contribute to exceeding any state or federal AAQS and will not negatively impact visibility in Class I areas. The modeling addresses emissions from construction activities and routine plant operations (including startups and shutdowns). The impacts from construction activities include fugitive dust and emissions associated with combustion by-products from diesel- and gasoline-fueled equipment. The impacts from routine plant operations are associated with combustion by-products from the turbine/HRSG, emergency generator, diesel fire pump engine and particulate emissions from the cooling tower. Separate modeling analyses were performed for the construction and the plant operation sources because they will occur during different time periods and have different emission rates. An air quality modeling protocol was prepared and submitted to both BAAQMD and SJVAPCD for review and comment. Comments received from both agencies were incorporated into the final modeling analysis. The modeling approach for assessing the TPP impacts is discussed below.

Model and Model Options. The modeling was conducted using the U.S. EPA's Industrial Source Complex (ISC) model (Version 00101) for both construction and turbine emissions (U.S. EPA, 1995b). The short-term model version, ISCST3, was used for modeling concentrations of pollutants having short-term (i.e., 1-, 3-, 8-, and 24-hour) ambient standards. The ISCST3 model is the most appropriate model because it is a U.S. EPA guideline model for plume dispersion in simple and complex terrain. For pollutants having both short-term and annual standards (i.e., NO_2, SO_2, and PM_{10}), modeling was conducted using ISCST3 with the PERIOD option to predict impacts on the annual standard. The ISCST3 model was run with the following additional options:

- Final plume rise at all receptors;
- Stack-tip downwash;
- Buoyancy-induced dispersion;
- Calms processing;
- Default wind profile exponents;
- Default vertical potential temperature gradients; and
- Rural dispersion coefficients.

Building Wake Effects. The effect of building wakes (i.e., downwash) on the stack plumes was evaluated for the routine plant operating emissions (downwash is not applicable to area sources, i.e., construction activities) in accordance with U.S. EPA guidance (U.S. EPA, 1985). Direction-specific building data were generated for stacks below good engineering practice (GEP) stack height using U.S. EPA's Building Profile Input Program (BPIP) (Version 98086 [U.S. EPA, 1995c]). Fifteen buildings, tanks and large pieces of equipment from the proposed TPP layout were included in the analysis (Figure 5.2-6). The results of the BPIP analysis were included in the ISCST3 input files to assess downwash effects. The ISCST3 model considers direction-specific downwash using both the Huber-Snyder and Schulman-Scire algorithms as evaluated in the BPIP program. Input and output files for the BPIP analysis are included in Appendix K-6.

Meteorological Data. Meteorological data, including wind speed, wind direction and sigma theta, were obtained from a station near the site owned and operated by a wind turbine company. The location of the station, known as Station 442, is shown in Appendix K-1. Temperature data was taken from the Tracy monitoring station which is operated by the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD). Data from 1997 and 1999 were used in the modeling analysis. Both years have greater than 90% data capture.

Wind patterns in the region surrounding the TPP site are shown using windroses from a number of meteorological stations near the project area. Windroses from the following meteorological stations are located in Appendix K-2:

- Tracy (SJVUAPCD site)
- Martin-1
- Station 442

The locations of these stations are shown in Appendix K-1. The Martin-1 station was located just to the north of the TPP site boundary at an elevation of approximately 500 feet. The Martin-1 site was a 12-meter tower that was operated several years ago, but is no longer active.

The windroses mentioned above all indicate a consistent, high wind speed pattern with wind directions predominately towards flat terrain, from the west and west-southwest directions. These patterns are indicative of the influence of the Altamont Pass terrain. Analysis of stability indicates that D stability occurs a majority of the time at each site. This stability class is expected due to the high wind speeds in the area.

Receptor Locations. Receptors were placed at off-site locations to evaluate the impacts of the TPP (Figure 5.2-7). Receptor spacing was determined according to a receptor's distance from the property boundary. To ensure that the location of highest impact was identified, receptor spacing was closest at the property boundary and increased with distance. Receptors were placed out to 10 kilometers (km) from the property boundary. The following receptor spacing was used in the modeling analysis:

- 25-meter spacing along the property line and extending from the property line out to 100 meters for any project sources within 500 meters of the property line;
- 100-meter spacing within 1 km of project sources for any locations not covered by the 25-meter grid;
- 500-meter spacing within 1 to 5 km of project sources;
- 1,000-meter spacing within 5 to 10 km of project sources; and
- 25-meter grids on any hills where maximum impacts are shown to occur.

The receptor locations were designated using Universal Transverse Mercator (UTM) coordinates. Receptor elevations were obtained from United States Geological Survey (USGS) 7.5-minute electronic data.

Emission Scenarios. The modeling for the TPP required the determination of worst-case emissions scenarios for the following averaging periods and pollutants to demonstrate compliance with AAQS:

- 1-hour for CO, NO_2, and SO_2;
- 3-hour for SO_2;
- 8-hour for CO;
- 24-hour for PM_{10} and SO_2; and
- Annual for PM_{10}, NO_2, and SO_2.

Construction Impact Modeling. For construction activities, it was assumed that the combustion equipment emissions occur in the area of the construction zone within the TPP property boundary. The worst-case emission scenarios were used to model the construction equipment impacts (see Table 5.2-18). On-site construction impacts only were modeled.

Due to the large amount of construction equipment needed for the TPP, it was necessary to define a representative source or sources. It was assumed that the emissions will be uniformly emitted from three point sources within the construction zone. PM_{10} emissions from fugitive dust generated from construction at the main site only were modeled as a polygon area source. The area source was placed around the construction area. The emissions scenarios and release parameters for the construction activities are presented in Table 5.2-27.

Table 5.2-27. TPP Construction Release Parameters

Emissions Scenario	Stack Characteristics (for the Construction Zone)			
	Stack Height (m)	**Stack Diameter (m)**	**Exhaust Temp (K)**	**Exhaust Velocity (m/s)**
Construction Equipment[a]	3	0.152	622	70
Emissions Scenario	**Release Height (m)**	**Longest East-West Distance (m)**	**Longest North-South Distance (m)**	
Fugitive Dust	1.5	550	295	

[a]The data shown represent the surrogate stack and release parameters for three release points.

NO_2 impacts were estimated using the ozone limiting method (OLM). Ozone data was gathered for 1997 and 1999 from the nearby Tracy monitoring station.

Turbine Impact Screening Modeling. Screening modeling was performed to determine which turbine operating modes (i.e., load level, duct burner firing, ambient temperature) produced “worst-case” impacts for each pollutant and averaging time. The ISCST3 model (Version 00101) was used for screening modeling. For the screening analysis, the model was run with the 1999 meteorological data, building wake information and the receptor grid previously described.

The model simulated natural gas combustion emissions from four 19-foot-diameter (6.1-m), 200-foot-tall (60.96-m) stack. The stacks were modeled as point sources at their proposed locations. The stack parameters for each operating mode are shown in Table 5.2-28. Table 5.2-28 also details the screening modeling results for the twelve combustion turbine operating conditions. Modeling files are shown in appendix K-8.

Table 5.2-28. Turbine Impact Screening Results

	Winter Minimum - 17 °F				Yearly Average - 62 °F				Summer Maximum - 112 °F			
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
Duct Burner Status	On	Off	Off	Off	On	Off	Off	Off	On	Off	Off	Off
Stack Velocity (ft/sec)	61.9	62.6	47.7	37.9	57.6	58.1	45.0	36.8	55.1	55.8	41.2	34.7
Stack Temperature (°F)	186	197	180	168	186	195	179	169	186	197	178	171
ISCST3 Results [μg/mg^3]/[g/s]												
1-hour	5.9	5.9	6.2	7.0	5.9	5.9	6.3	7.1	6.0	5.9	6.5	**7.4**
3-hour	3.5	3.3	4.0	4.2	3.6	3.5	4.0	4.2	3.7	3.5	4.1	**4.3**
8-hour	1.9	1.7	2.3	2.7	2.0	1.9	2.4	2.8	2.0	1.9	2.5	**2.8**
24-hour	0.67	0.64	0.84	0.99	0.71	0.68	0.87	1.00	0.74	0.70	0.92	**1.03**
Annual	0.032	0.031	0.037	0.042	0.033	0.032	0.038	0.042	0.034	0.033	0.039	**0.042**

Bolded screening results represent maximum impact.

Refined Modeling. Refined modeling was performed to identify offsite criteria pollutant impacts from operational emissions of the proposed project. The modeling was performed as previously described. However, in addition to the turbine/HRSG, the emergency generator, fire pump engine and cooling tower were also included in the refined modeling analysis.

Based on the screening results, stack parameters from the 50% load, with no duct firing, at 112° F ambient temperature simulate worst-case dispersion. These parameters were used in the modeling to provide a conservative value for the pollutant dispersion. Pollutant emission rates for warm startups and cold startups (summarized in Table 5.2-21) were applied to these dispersion impacts to represent worst-case startup, short-term impacts of CO (1- and 8-hour) and NO_2 (1-hour), respectively. For NO_2 and CO 1-hour impacts, only two of the four turbines are considered to be in startup. The other two turbines are modeled in the non-startup mode that results in the highest hourly impacts for CO and NO_2, 100% load, with duct firing, at 17°F ambient temperature.

Annual average NO_2 and PM_{10} impacts were estimated using the stack parameters for the 100% load, with duct firing, at 60°F ambient temperature operating mode. Annual emission rates for NO_2 and PM_{10}, shown in Table 5.2-22 were used in the analysis.

The PM_{10} 24-hour impacts were based on the actual emissions rate and stack parameters for the 100% load, with duct firing, at 112°F ambient temperature operating mode. The screening analysis indicated that this operating mode results in the highest 24-hour PM_{10} impact. Details of the screening analysis are shown in Appendix K-8.

All SO_2 impacts were modeled using the stack parameters and emission rate from the 100% load, with duct firing, at 17° F ambient temperature operating mode. This operating mode results in maximum impacts for all SO_2 averaging times.

Annual NO_2 impacts were estimated using the ambient ratio method (ARM) with the U.S. EPA default ambient ratio of 0.75 applied to the ISCST3 model results. Hourly NO_2 impacts were estimated using the Ozone Limiting Method (OLM) with the ISC3_OLM model (Version 96113). Ozone data used in the OLM model was obtained from the Tracy Station for 1997 and 1999.

Fumigation Analysis. Fumigation occurs when a plume that was originally emitted into a stable layer of air is mixed rapidly to ground-level when unstable air below the plume reaches plume level. Fumigation can cause very high ground-level concentrations. Fumigation can occur during the break up of the nocturnal radiation inversion by solar warming of the ground surface (inversion break-up fumigation). Such conditions are short-lived and are typically compared only with 1-hour standards. A fumigation analysis was performed using the U.S. EPA SCREEN3 model (Version 96043). Appendix K-8 shows the modeling results for fumigation analysis.

5.2.4.5 Compliance with Ambient Air Quality Standards

Air quality impacts associated with the TPP emissions are compared to the applicable short-term and long-term AAQS in this subsection. The impacts from construction activities and routine plant operations are evaluated separately because they will occur during different time periods and represent different sources. ISCST3 model results for each averaging time were added to the maximum background concentrations obtained from the most recent three years of air quality data (i.e., 1997–1999). These background air quality data are presented in Section 5.2.2.2.

The maximum air quality impacts are compared with the most stringent state or federal AAQS. Table 5.2-29 summarizes modeling results for construction and operation. The worst-case air quality impacts are plotted in the isopleth maps shown in Figures 5.2-8 through 5.2-17 (NO_2, CO, PM_{10}, and SO_2 impacts).

Construction Activities. Construction emissions are of a temporary nature and will not coincide with emissions from plant operations. The maximum air quality impacts from construction activities were predicted to occur along the northern and southern boundaries of the facility. No exceedance of AAQS is predicted to occur except for PM_{10} (both daily and annual averaging periods) and NO_x (1-hour averaging period). Although daily and annual PM_{10} and maximum hourly NO_x exceedances are predicted during construction activities, these impacts are only temporary. For NO_x, the AAQS was exceeded in only one of the years modeled, 1999. The NO_2 impacts are conservatively high due to the assumption used in the modeling that all of the ambient ozone will convert the NO released to NO_2 during the relatively short transport time (less than 3 minutes) to the areas of highest impact. In reality, most of the NO released will not have time to react with ozone to form NO_2 in the amount of time it takes the plume to reach the TPP site boundaries. In addition, the localized impact is away from residences in a more sparsely populated area. The maximum impact occurs at the TPP fenceline. Construction mitigation measures, described in Section 5.2.3, will be used to minimize impacts from temporary construction emissions consistent with other projects considered by the Commission. Construction modeling outputs are included in Appendix K-7.

Table 5.2-29. TPP Project ISCST3 Modeling Results

Pollutant	Averaging Period	Maximum Modeled Impact (µg/m³)	PSD Significant Impact Level[a] (µg/m³)	Background[b] (µg/m³)	Total Predicted Concentration (µg/m³)	AAQS (µg/m³)	UTM Coordinates East (m)	UTM Coordinates North (m)
Construction Impacts								
CO	1-hour	571	NA	13,054	13,625	23,000	626,675	4,176,050
	8-hour	292.8	NA	8,405	8,698	10,000	625,725	4,175,901
NO_2	1-hour	292.5[c]	NA	199	492	470	626,490	4,175,919
	Annual	23.4[d]	NA	45.2	76.4	100	626,250	4,176,150
PM_{10}	24-hour	42.46	NA	150	192.5	50	626,214	4,176,162
	Annual	8.56	NA	40.9	49.5	30	626,269	4,176,121.5
SO_2	1-hour	117.9	NA	29.3	147	655	626,675	4,176,050
	3-hour	73.9	NA	29.3	103	1,300	626,675	4,176,025
	24-hour	47.2	NA	16	63.2	105	625,725	4,175,901
	Annual	3.07	NA	8	11.1	80	626,250	4,176,150
Routine Plant Operation Impacts								
CO	1-hour	1,717	2,000	13,054	14,771	23,000	624,300	4,173,800
	8-hour	274.3	500	8,405	8,679	10,000	624,300	4,173,775
NO_2	1-hour	230.5[c]	NA	199	430	470	625,947	4,176,129
	Annual	0.19[d]	1	45.2	45.4	100	621,400	4,175,500
PM_{10}	24-hour	4.859	5	150	154.9	50	622,700	4,174,050
	Annual	0.847	1	40.9	41.75	30	626,375	4,176,225
SO_2	1-hour	79.7	NA	29.3	108.6	655	625,842	4,176,030
	3-hour	11.45	25	29.3	40.75	1,300	626,525	4,176,075
	24-hour	0.725	5	16	16.7	105	623,675	4,172,900
	Annual	0.036	1	8	8.04	80	621,375	4,175,500

a Source: 40 CFR 52.21

b Background represents the maximum value measured at Tracy Patterson Pass Road, Stockton Hazelton Street, and Modesto 14th Street, 1997-1999. SO_2 Data from Bakersfield, Chester Street and 5558 California Ave Stations, 1997 and 1999.

c Results used OLM to estimate NO_2 impacts

d Results used ARM with default ratio of 0.75.

AAQS = Most stringent ambient air quality standard for the averaging period.
ARM = Ambient Ratio Method
NA = Not applicable
NR = Not reported
m = meters
OLM = ozone limiting method
µg/m³ = micrograms per cubic meter
CO = carbon monoxide
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than or equal to 10 microns in diameter
SO_2 = sulfur dioxide

Routine Plant Operations. Maximum modeled impacts due to plant operation emissions would not cause a violation of any federal or state AAQS and would not significantly contribute to the existing violations of the PM_{10} standards. In addition, the project impacts are below significance levels established under PSD regulations. Therefore, no PSD increment consumption analysis is required. The location of maximum impact for all criteria pollutants and averaging times are indicated by a star symbol on Figures 5.2-8 through 5.2-17.

Fumigation impacts were estimated as described in Section 5.2.4.3 and are all below applicable short-term AAQS. The fumigation impacts are summarized in Table 5.2-30.

Table 5.2-30. TPP Fumigation Impacts

Pollutant	SCREEN3 Inversion 1-hr Result [μg/m3]/[g/s]	Emission Rate Per Turbine (lb/hr)	Maximum Impact – All Turbines (μg/m^3)	Background (μg/m^3)	Total	Lowest AAQS
CO 1-hour	1.557	663	520.3	13,054	13,574	23,000
CO 8-hour	1.557	165.4	90.8	8,405	8,496	10,000
NO_2 1-hour	1.557	150	117.7	199	317	470
SO_2 1-hour	1.557	2	1.57	29.3	31	655
SO_2 3-hour	1.557	2	1.41	29.3	31	1,300

Impacts for Nonattainment Pollutants and their Precursors. TPP impacts for the nonattainment pollutants (PM_{10} and ozone) and their precursors (NO_x, VOC, and SO_2) will be mitigated by emission offsets. The offsets have not been accounted for in the modeled impacts noted above.

5.2.4.6 Air Quality Related Value Impacts - Visibility

Specific national parks, wilderness areas and national monuments are designated as Class I areas and are protected by PSD regulations. The PSD regulations require an assessment of the impacts of major sources on air quality-related values (AQRVs) in Class I areas. AQRVs include:

- Visibility,
- Terrestrial resources (e.g., vegetation, geological features, wildlife); and
- Aquatic resources (e.g., lakes, streams, aquatic biota).

TPP is not subject to PSD requirements for AQRVs because the nearest Class I area (Point Reyes National Seashore) is more than 100 kilometers from the site. BAAQMD Rule 2-2-417 requires that AQRVs be investigated to ensure that nearby Class I areas are not affected by the TPP. As the Federal Land Manager (FLM) for the closest Class I area (i.e., Point Reyes National Seashore), the National Forest Service and the National Park Service are responsible for establishing the AQRVs for each area. The FLM has the legal responsibility for identifying and describing AQRVs in each Class I area and for defining each AQRV's limit of acceptable change (LAC).

Effects on Visibility. The CAA established the importance of visibility for Class I areas by declaring a goal to prevent future visibility impairment and remedy existing visibility impairment due to man-made air pollution. The CAA also specifically requires that visibility be addressed as an AQRV within all Class I areas.

To quickly assess the potential impact of individual plumes on visibility, U.S. EPA has developed a plume visual impact screening model (VISCREEN) that accounts for specific transport and dispersion conditions (U.S. EPA, 1992). Level I and Level II screening levels can be conducted using VISCREEN. If the Level I and Level II analyses fail, then more sophisticated visibility models are needed to conduct a more complex Level III analysis.

VISCREEN uses two scattering angles (θ) to calculate potential plume visual impacts. The scattering angle is the angle between direct solar radiation and the line of sight. Thus, if an observer is looking directly at the sun, then θ equals 0°; if the observer is looking away from the sun, then θ would equal 180°. The first scattering angle ($\theta = 10°$) represents the forward scatter case, where the plume is likely to be the brightest; the second scattering angle ($\theta = 140°$) represents the backward scatter case, where the plume is likely to be the darkest.

The impacts of the TPP on visibility at Point Reyes National Seashore were assessed using the VISCREEN model. Details of this analysis are located in Appendix K-9. VISCREEN requires emission rate inputs for five "visibility species" (i.e., directly emitted PM_{10}, NO_X, directly emitted NO_2, soot or elemental carbon, and directly emitted sulfate) and a maximum background visual range. For this project, worst case hourly emission rates for PM_{10} and NO_x were used. The remaining three species were assumed to be negligibly small for natural gas fired combustion equipment.

For Level I screening, conservative meteorological conditions (i.e., F stability class and a 1.0 m/s wind that persists for 12 hours) were used to estimate worst-case plume visual impacts. As shown in Table 5.2-31, Level I screening for the Point Reyes National Seashore failed one of eight screening criteria. Because Level I screening failed for the nearest Class I area, the more detailed Level II screening was performed.

Level II screening uses more realistic (i.e., less conservative) input data than Level I screening. For Level II screening, actual meteorological data are used rather than unrealistically conservative wind speeds and stability. The meteorological data used in the air quality impact analyses and the public health analyses (see Section 5.15) were examined to determine the worst-case stabilities and wind speeds that might transport the plume in the direction of the Class I area.

It was determined that a realistic worst-case dispersion condition for visibility modeling for the Point Reyes National Seashore was an F stability class and a 3.0 m/s wind. Using these meteorological conditions, Level II screening was performed. Table 5.2-32 shows that Level II screening successfully passed all screening criteria.

Table 5.2-31. Level I Visual Effects Screening Analysis for Point Reyes National Seashore

Input Emissions	
Particulates	63 lb/hr
NO_x (as NO_2)	600 lb/hr
Primary NO_2	0.00 lb/hr
Soot	0.00 lb/hr
Primary SO_4	0.00 lb/hr
Transport Scenario Specifications	
Background Ozone	0.04 ppm
Background Visual Range	128 km
Source-Observer Distance	102.0 km
Minimum Source-Class I Distance	102.0 km
Maximum Source-Class I Distance	140.0 km
Plume-Source-Observer Angle	11.25 degrees
Stability Class	F (6)
Wind Speed	1.00 m/s

Maximum Visual Impacts INSIDE Class I Area (Screening Criteria ARE Exceeded)*

					ΔE		Contrast	
Background	**Theta**	**Azimuth**	**Distance**	**Alpha**	**Criteria**	**Plume**	**Criteria**	**Plume**
Sky	10.0	84.0	102.0	84.0	2.00	2.051*	0.05	0.002
Sky	140.0	84.0	102.0	84.0	2.00	1.054	0.05	-0.016
Terrain	10.0	84.0	102.0	84.0	2.00	0.760	0.05	0.010
Terrain	140.0	84.0	102.0	84.0	2.00	0.236	0.05	0.005

Notes:

* Screening criteria ARE exceeded .

Lb/hr = pounds per hour

km = kilometers

m/s = meters per second

ppm = parts per million

Table 5.2-32. Level II Visual Effects Screening Analysis for Point Reyes National Seashore

Input Emissions	
Particulates	63 lb/hr
NO_x (as NO_2)	600 lb/hr
Primary NO_2	0.00 lb/hr
Soot	0.00 lb/hr
Primary SO_4	0.00 lb/hr
Transport Scenario Specifications	
Background Ozone	0.04 ppm
Background Visual Range	128 km
Source-Observer Distance	102.0 km
Minimum Source-Class I Distance	102.0 km
Maximum Source-Class I Distance	140.0 km
Plume-Source-Observer Angle	11.25 degrees
Stability Class	F (6)
Wind Speed	3.00 m/s

Maximum Visual Impacts INSIDE Class I Area (Screening Criteria ARE NOT Exceeded)

					ΔE		**Contrast**	
Background	**Theta**	**Azimuth**	**Distance**	**Alpha**	**Criteria**	**Predicted Plume**	**Criteria**	**Predicted Plume**
Sky	10.0	84.0	102.0	84.0	2.00	1.629	0.05	0.001
Sky	140.0	84.0	102.0	84.0	2.00	0.839	0.05	-0.013
Terrain	10.0	84.0	102.0	84.0	2.00	0.601	0.05	0.008
Terrain	140.0	84.0	102.0	84.0	2.00	0.186	0.05	0.004

Notes:
Lb/hr = pounds per hour
km = kilometers
m/s = meters per second
ppm = parts per million

Terrestrial Resources. Maximum modeled NO_2 and SO_2 impacts from normal plant operations, as well as estimates of total sulfur and nitrogen deposition from these modeled concentrations, were compared against U.S. Forest Service (USFS, 1992) significant impact thresholds for vegetation and ecosystems for Class I Wilderness Areas. Table 5.2-33 summarizes the maximum modeled impacts versus the USFS significance criteria. All impacts are below USFS significance criteria.

Deposition rates were estimated by assuming that all of the nitrogen and sulfur in the modeled NO_2 and SO_2 gases is converted to elemental sulfur and nitrogen in the particulate phase and is deposited on the ground. However, because this would not normally occur, this assumption is extremely conservative. The deposition rate was calculated by multiplying the modeled airborne concentration by a deposition velocity of 0.02 m/s. This deposition velocity is consistent with California Air Pollution Control Officers Association (CAPCOA) guidelines for estimating deposition rates (CAPCOA, 1993). The impacts on crops are discussed in Section 5.3.5.3.

Table 5.2-33. Maximum Modeled Soil and Vegetation Impacts of the Proposed Project

Pollutant	USFS Significance Level	Maximum Project Impact
SO_2 Annual	8 ppbv	0.016 ppbv (0.042 $\mu g/m^3$)
SO_2 Hourly	40 ppbv	30 ppbv (79.8 $\mu g/m^3$)
NO_2 Annual	15 ppbv	0.18 ppbv (0.34 $\mu g/m^3$)
Total Sulfur Deposition	5 kg/ha-yr	0.13 kg/ha-yr
Total Nitrogen Deposition	3 kg/ha-yr	0.65 kg/ha-yr

Notes:
kg/ha-yr = kilograms per hectare per year
$\mu g/m^3$ = micrograms per cubic meter
ppbv = parts per billion, by volume
USFS = U.S. Forest Service

Adverse effects of project emissions on wildlife are not expected. The NAAQS and CAAQS are established to protect the health of people who are the most susceptible to air pollutants. Because impacts from the project's air emissions have been demonstrated to be below significance levels, no adverse impacts to wildlife are expected.

Cooling Tower Water Vapor Plumes

The Tesla Power Plant cooling tower will be a plume abated cooling tower. The plume abated tower incorporates a dry-cooling section which when activated, reduces the relative humidity of the cooling tower exiting air. This results in elimination of the plumes or significant reduction in their size and frequency of occurrence. The plume abatement operation will be utilized during times when plumes are most likely to be visible. Generally, plumes are most likely to be a visible impediment to an observer during daytime hours. Most visual contrast can be seen during daytime hours when no fog is present.

The water vapor plumes were modeled using SACTI. However, it should be noted that, the SACTI model predicts generally conservative results, as it tends to overestimate realistic plume dimensions. In addition, it was not developed to predict the vapor plumes from the plume abated tower. To illustrate the effectiveness of the plume abatement, the cooling tower operation was modeled for both the all daytime hours and daytime hours without fog conditions. The modeling results are summarized in Table 5.2-34. The results are broken down into six categories:

- All hours, which includes both day and night hours and both fog and no fog conditions;
- All hours – no fog, which includes both day and night hours but excludes hours when fog is present;

- Day hours, which includes both fog and no fog conditions during daytime hours only;
- Day – no fog, which includes only daytime hours when fog is not present;
- Night hours, which includes both fog and no fog conditions during nighttime hours only; and
- Night – no fog, which includes only nighttime hours when fog is not present.

Modeled plume dimensions (i.e., length, height, and width) were divided into four categories (i.e., 0-40 meters, 40-100 meters, 100-400 meters, and greater than 400 meters) and a frequency of occurrence was calculated for each size range.

Without plume abatement for normal operation during daytime hours when no fog is present, the height of the water vapor plume will be less than forty meters about 82% of the time. The plume height will range from forty to one hundred meters about 11% of the time, and will be greater than 100 meters high about 7% of the time.

The results of abatement operation (as shown in Table 5.2-34) are impressive. During daytime hours with no fog present, the plume heights will be less than 40 meters about 92% of the time, between 40 and 100 meters about 3% of the time, and between 100 to 400 meters about 5% of the time

Aquatic Resources. A significant effect of NO_x and SO_2 emissions on aquatic resources is nitrogen and sulfur deposition and subsequent acidification. However, because any increased nitrogen and sulfur deposition due to the proposed project would be minimal, impacts to water acid neutralizing capacity (ANC) and pH, and, therefore, acidification or eutrophication, are not likely to occur.

5.2.4.7 Commissioning Impacts

An ISC_OLM modeling analysis using a NO_x emission rate of 19.593 g/s (155.5 lb/hr) and 50% load stack parameters indicates that the maximum modeled one-hour NO_2 impact during commissioning is 201 $\mu g/m^3$. This is lower than the maximum modeled one-hour NO_2 impact from the facility as a whole, as shown in Table 5.2-29. With the maximum background NO_2 one-hour concentration of 199 $\mu g/m^3$, the maximum total impact would be 400 $\mu g/m^3$, which is well below the state one-hour NO_2 standard of 470 $\mu g/m^3$. A modeling analysis of CO one-hour impacts was also conducted using an emission rate of 95.4 lb/hr and 50% load stack parameters. The maximum modeled impact was 376.7 $\mu g/m^3$. Modeling of turbine commissioning for 8-hour CO impacts was not completed because the CO 8-hour emission rate (including startups) of 165.4 lb/hr is under the 50% load case (Case 12) was used to model impacts. These 8-hour CO impacts (shown in Table 5.2-29) will be worst case for 8-hour CO when compared to commissioning activities. Modeling output files are in Appendix K-10.

5.2.4.8 Cumulative Impacts Analysis

CEQA requires an analysis to determine the cumulative impacts of the TPP and other projects. For purposes of the CEC analysis, projects within a 6-mile radius that have received construction permits but are not yet operational or that are in the permitting process have been considered. The cumulative impact analysis assesses whether estimated emissions concentrations may cause or contribute to a violation of any ambient air quality standard.

A listing of facilities that are permitted but not yet in operation or in the permitting process within a 6-mile radius of the TPP was requested from both BAAQMD and SJVAPCD. SJVAPCD did not have any facilities that met this criterion. BAAQMD provided stack parameters and emissions for the East Altamont Energy Center. Midway Power, LLC, obtained additional information the Tracy Peaker Project. The cumulative impacts analysis modeled the TPP in start-up operation when emissions are worst-case. Emissions from other sources were modeled under normal operating conditions. Stack parameters and emissions for sources used in the cumulative impacts analysis are shown in Table 5.2-35. Results of the analysis are shown in Table 5.2-36. Modeling output files are in Appendix K-11.

Table 5.2-35. Stack Parameters and Emissions for Sources Used in Cumulative Impacts Analysis

Unit	UTM East	UTM North	Elevation (ft)	Stack Height (ft)	Temp. (K)	Velocity (ft/s)	Diameter (ft)
Stack Parameters							
Tracy Peaker Turbines	633,100	4,174,603	177	100	727.6	120	17
East Altamont Turbines	625,550	4,184,800	49	175	334.26	55.3	18.5
East Altamont Boiler	625,550	4,184,800	49	100	436	17.1	7.1
East Altamont Cooling Towers	625,550	4,184,800	49	45	294.3	32.8	33.7

	NO_x (lb/hr)	CO (lb/hr)	SO_2 (lb/hr)	PM_{10} (lb/hr)
Emissions				
Tracy Peaker Turbines	34.48	100.86	1.0	19.1
East Altamont Turbines	59.57	209.1	4.86	45.8
East Altamont Boiler	1.5	5.0	0.09	2.65
East Altamont Cooling Towers	0.0	0.0	0.0	2.40

Results indicate that the TPP, when combined with surrounding future projects, will not cause an exceedence or contribute to an existing exceedence of the ambient air quality standards. In addition, the ground-level impacts will not exceed the PSD Significant Impact Level and, therefore, an increment consumption analysis is not necessary.

Table 5.2-36. Cumulative Impacts Analysis Results

Pollutant	Averaging Period	Maximum Modeled Impact (μg/m³)	PSD Significant Impact Level[a] (μg/m³)	Background[b] (μg/m³)	Total Predicted Concentration (μg/m³)	AAQS (μg/m³)	UTM Coordinates East (m)	UTM Coordinates North (m)
CO	1-hour	1,361.1	2,000	13,054	14,415.1	23,000	624,500	4,173,500
	8-hour	189.6	500	8,405	8,594.6	10,000	624,000	4,173,000
NO_2	1-hour	230.5[c]	NA	199	429.5	470	625,947	4,176,129
	Annual	0.37[d]	1	45.2	45.6	100	627,000	4,186,000
PM_{10}	24-hour	4.54	5	150	154.5	50	623,500	4,173,000
	Annual	0.65	1	40.9	41.6	30	626,375	4,176,225
SO_2	1-hour	79.71	NA	29.3	109.0	655	625,842	4,176,030
	3-hour	11.45	25	29.3	40.8	1,300	626,525	4,175,500
	24-hour	0.67	5	16	16.7	105	623,500	4,173,000
	Annual	0.036	1	8	8.0	80	621,500	4,175,500

5.2.5 Mitigation

BAAQMD rules require that operational emissions of the proposed project be offset by emission reductions at other sources within or outside the TPP. Specifically, Regulation 2, Rule 2, Section 302, "Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides," requires that federally enforceable emission offsets are required from permitted sources with emissions of NO_X or POC exceeding 15 tons per year (tpy). For facilities that will emit 50 tpy or more of these pollutants, emissions offsets must be provided at a ratio of 1.15 to 1.0. Because TPP is expected to have annual emissions of 245.76 tpy of NO_X and 58.91 tpy of POC, emission credits for these pollutants must be provided in the amounts of 282.62 tpy and 67.75 tpy, respectively. Credits for POC may be used to offset NO_X emissions at a 1:1 ratio.

Section 303, "Offset Requirements, PM_{10} and Sulfur Dioxide," requires that offsets be required at a 1:1 ratio by proposed sources that will emit more than 100 tpy of either PM_{10} or SO_2. Projected annual emissions of PM_{10} and SO_2 from the proposed project are 195.6 tpy and 29.50 tpy, respectively. Accordingly, emission reduction credits in these amounts are required under BAAQMD.

Midway Power, LLC currently holds six certificates in the BAAQMD emission bank (# 710, 718, 719, 720, 762, and 767). These certificates will be used to partially offset the project emissions. In addition, the TPP has contacted holders within the BAAQMD to acquire the remaining NO_X, POC, and PM_{10} emission reduction credits required under Rule 2, Section 302 and 303. The TPP has been able to execute option agreements with several other credit holders and is currently engaged in discussions for purchase agreements with additional offset holders. The ongoing negotiations reveal it will be necessary to use interpollutant trading of POC credits to offset a portion of the projects NO_X emissions. In order to obtain a sufficient amount of PM_{10} offsets the TPP is in discussion with a third party to obtain offsets from paving roads. Additional information detailing the proposed ERC package will be filed with the CEC under separate cover with a request for confidentiality under Title 20, California Code of Regulations 2501 et seq.

5.2.6 Compliance with Laws, Ordinances, Regulations, and Standards

All applicable LORS are summarized in Section 5.2.1 along with the administering agency. The TPP will comply with all applicable air quality LORS as explained in Table 5.2-37. It should be noted that in order to demonstrate compliance with several LORS, the TPP will install and operate a continuous emissions monitoring (CEM) system.

In summary, the TPP will comply with all applicable LORS, conform to BACT requirements, and will not interfere with attainment or maintenance of California and federal AAQS. In addition, the TPP emissions (NO_x, VOCs, PM_{10}, and CO) will be fully offset.

Table 5.2-37. TPP Summary of Compliance with Air Quality LORS

Authority	Administering Agency	Requirements	TPP Compliance
Federal CAAA of 1990; 40 CFR 50	U.S. EPA Region IX, CARB, BAAQMD	National Ambient Air Quality Standards (NAAQS)	The TPP operations will not cause a violation of any national (or state) ambient air quality standard.
40 CFR 52.21, BAAQMD Regulation 2, Rule 2	U.S. EPA Region IX, CARB, BAAQMD	PSD Requirements	Air quality modeling (Section 5.2.4) demonstrates that the TPP will not interfere with the attainment or maintenance of NAAQS or exceed applicable PSD increments.
40 CFR 72, 73, 75; BAAQMD Regulation 2, Rule 7	BAAQMD	Acid rain requirements, SO_2 allowances.	The TPP will submit an acid rain permit application within two years before startup. Continuous emissions monitoring (CEM) will be implemented.
40 CFR 60, Subpart GG; BAAQMD Regulation 10	BAAQMD	New Source Performance Standards (NSPS); 0.010% by volume (100 ppmv) for NO_x and 0.015% by volume (150 ppmv) for SO_2.	The TPP emission rate for NO_x is 2.0 ppmv at 15% O2; the SO_2 emission rate is 0.19 ppmvd at 15% O2. Both emission rates are well below the NSPS emission limit. Additionally CEM plans will be developed and CEM will be performed.
40 CFR 70, BAAQMD Regulation 2, Rule 6	BAAQMD	Federally Mandated Operating Permit (Title V) for major sources	The Title V permit application will be submitted within 12 months of startup of the TPP.
California Administrative Code, Title 14, §15002(a)(3), CEQA Guideline	CEC	Power plant siting requirements.	This AFC satisfies the CEC requirements.
H&S Code § 44300	BAAQMD	Air toxics "Hot Spots" emission inventory.	An inventory will be prepared after commencement of operation.

Table 5.2-37. TPP Summary of Compliance with Air Quality LORS (Continued)

Authority	Administering Agency	Requirements	TPP Compliance
Regulation 1, Section 301	BAAQMD	Nuisance; prohibits discharge of emissions which cause injury, illness, detriment, nuisance, etc., to any considerable number of persons or to the public.	The TPP will ensure compliance with the rule by using natural gas for combustion and maintaining ammonia slip substantially below the odor threshold. The public health analysis (Section 5.15) also demonstrates that no significant adverse health impacts are expected.
Regulation 2, Rule 3	BAAQMD	Authority to Construct (ATC) and Permit to Operate (PTO).	This AFC contains all of the information required by the BAAQMD.
Regulation 2, Rule 2	BAAQMD	New Source Review (NSR).	NSR requirements will be met by the TPP and are demonstrated in Sections 5.2.3, 5.2.5, and 5.2.4.
Regulation 6	BAAQMD	Limits particulate matter and visible emissions	The TPP will ensure compliance with the rule by using natural gas and effective combustion practices. Excess visible emissions are not anticipated from properly operating natural gas–fired combustion equipment.
Regulation 7	BAAQMD	Prohibits discharge of odorous substances	The TPP is expected to be in compliance with this rule because the ammonia emissions from the SCR units will be limited to 5 ppmvd at 15 percent O_2 each
Regulation 8	BAAQMD	Limits the emission of organic compounds	Solvents used in cleaning and maintenance are expected to comply with Regulation 8, Rule 4, by emitting less than 5 tons per year of volatile organic compounds.
Regulation 9, Rule 1	BAAQMD	Limits sulfur dioxide ground level concentrations	Modeling shows that the TPP will not violate this rule.
Regulation 9, Rule 1	BAAQMD	Limits NOx from heat transfer operations	All units at the TPP will emit less than 125 ppm of NOx and are expected to comply with this rule.
Regulation 9, Rule 7	BAAQMD	Limits emissions of NOx and CO from the duct burners.	The duct burners after controls are expected to emit a maximum of 2.0 ppmvd of NO_x and 6 ppmvd of CO. These emissions are in compliance with this regulation.
Regulation 9, Rule 9	BAAQMD	Restricts NOx emissions from gas turbines to 9 ppm	Turbine NOx emissions will meet BACT guidelines of 2.0 ppmvd.

5.2.7 Permitting Schedule

Midway Power, LLC will submit a copy of the AFC to BAAQMD. The AFC contains all of the information required by BAAQMD.

5.2.8 Agency Contacts

The air quality agencies having authority over construction and operation of the TPP are provided in Table 5.2-38.

Table 5.2-38. Involved Agencies and Agency Contacts

Agency	Contact/Telephone	Permits/Reason for Involvement
Bay Area Air Quality Management District 939 Ellis Street San Francisco, CA 94109	Richard Wocasek (415) 771-6000	Determination of Compliance
U.S. EPA, Region IX 75 Hawthorne Street San Francisco, CA 94105	Jack Broadbant (415) 744-1259	Prevention Significant Deterioration

5.2.9 References

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